Powers Engineering

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Subject: Powers Engineering comments on EPA 316(b) March 28, 2011 TDD

Dear Reed:

This comment letter summarizes my review of the EPA's March 28, 2011 Technical Development Document for the Proposed Section 316(b) Phase II Existing Facilities Rule (2011 TDD). The Powers Engineering review addresses the reasonableness of cooling tower retrofit capital costs identified by the EPA, projected turbine efficiency penalties and cooling tower parasitic fan and pump loads imposed by cooling towers, cooling tower retrofit downtime, air pollution impacts, cooling tower space requirements, uncertainties regarding useful remaining plant life, permit application requirements, and related issues.

I. Summary of Findings

- EPA's reliance on the Electric Power Research Institute (EPRI) cooling tower cost spreadsheet results in average wet inline cooling tower retrofit capital costs that are approximately 45 percent higher than the capital costs estimated by the EPA's own cooling tower retrofit cost model for wet inline cooling towers.

- The EPRI spreadsheet capital cost estimate for a mix of 75 percent inline wet cooling towers and 25 percent inline plume-abated in-line cooling towers is more than 30 percent higher than a composite estimate based on EPA's own cost model for wet inline cooling towers and a leading cooling tower manufacturer's cost estimate for plume-abated <u>back-to-back</u> cooling towers.

- The EPRI cooling tower cost spreadsheet turbine efficiency penalty imposed by a cooling tower retrofit on a fossil plant of 1.50 percent is more than four times the 0.35 percent estimate in the EPA cooling tower cost model, and approximately ten times the 0.16 percent average turbine efficiency penalty measured for the 346 MW Jeffries coal plant cited by the EPA in the 2002 TDD.

- The EPRI cooling tower cost spreadsheet turbine efficiency penalty imposed by a cooling tower retrofit on a nuclear plant of 2.50 percent is more than six times the 0.40 percent estimate in the EPA cooling tower cost model. The EPA estimate is consistent with the turbine efficiency penalty projected for cooling tower retrofits at the Indian Point Nuclear Generating Station based on the cooling tower performance data provided by the plant owner.

- The EPRI cooling tower cost spreadsheet overestimates the fan and pump energy penalties imposed by a cooling tower retrofit by about 30 percent relative to the EPA cost model.

- EPA overestimates the typical downtime required for cooling tower hook-up at a fossil plant by a factor of two in the 2002 TDD and repeats the overestimate in the March 2011 TDD. EPA identified one month as the upper end of the range for typical hook-ups, based on a review of actual cooling tower retrofits, but then stated that two months are assumed to be necessary.

- EPA provides no substantial evidence for the assumption in the March 2011 TDD that seven months of downtime are necessary for a cooling tower retrofit at a nuclear plant. The agency provides only vague references to safety concerns, and these are contradicted in the same document. The 2002 TDD correctly assumed that nuclear plants would require the same cooling tower hook-up downtime as fossil plants.

- EPA's estimates that total annualized national pre-tax compliance costs for power plants under Option 2 and Option 3 would be $4,933 million and $5,079 million, respectively. These estimates are high by more than 60 percent. More realistic national pre-tax compliance costs for Option 2 and Option 3 are $3,029 million and $3,104 million annually.

- EPA ignores clean air rules that will result in a substantial drop in air pollution emissions from coal plants, and a gradual and steady shift from coal to natural gas for electric power generation for economic reasons, in asserting an increase in air emissions from cooling tower conversions. What would occur is a slightly less dramatic drop in air emissions from fossil plants over time, not an increase in air emissions.

- EPA ignores the most likely cooling tower configuration at space-constrained sites, the back-to-back in-line cooling tower configuration, in postulating a potential minimum space requirement of at least 160 acres per 1,000 MW of capacity for cooling towers to be feasible. The space requirement of back-to-back cooling towers is less than one-fifth the space requirement of the inline cooling towers assumed by EPA in the March 2011 TDD. Inclusion of back-to-back cooling tower(s) in the scope of the analysis would result in this cooling tower option being presumptively feasible from a space requirement standpoint in essentially all cases.

- Uncertainties regarding useful remaining plant life are easily addressed by allowing plant operators to commit to a permanent plant closure date of no later than 2020 to avoid a cooling tower retrofit. If the plant owner opts not to commit to closure, then the units should get no special consideration from the EPA regarding remaining useful life.

- EPA should define the expected retrofit cooling tower cost and O&M values to be used in permit applications to minimize the tendency of each applicant to "reinvent the wheel" to the detriment of actually carrying-out a cooling tower conversion. These default values should reflect the agency's extensive evaluation and verification of these costs and parameters. Recommended default values for permit applications are (installed cost range represents range in cooling tower cost from 12 ^{o}F to 8 ^{o}F design approach temperature):

Installed cost, wet tower (in-line or back-to-back), $/gpm:	182 – 223
Installed cost, plume-abated tower (in-line or back-to-back), $/gpm:	316 – 411
Average turbine efficiency penalty (fossil or nuclear), %:	0.30 – 0.40
Average fan parasitic energy penalty (fossil or nuclear), %:	0.40 – 0.60
Average pump parasitic energy penalty (fossil or nuclear), %:	0.40 – 0.60
Total retrofit downtime, months:	fossil – 1, nuclear – 2

- EPA employees or EPA contractors should be the sole arbiters of the technical adequacy of applications, not peer reviewers hired by the applicant. Peer reviewers hired by the applicant will generally become advocates for the applicant's position, whether or not that position is technically sound.

- Many existing once-through cooling (OTC) plants previously subject to the Phase II rule have already prepared cooling tower conversion studies. As a result, the start-to-finish application process for cooling tower conversions should be no more than 24 months. The cooling tower retrofit should be completed no more than 36 months after approval of the application. The one exception would be nuclear plants that may need up to 12 additional months to synchronize the cooling tower retrofit outage with a refueling outage.

II. Review of EPA's analysis of the costs associated with retrofitting and operating closed-cycle cooling towers at existing nuclear and fossil-fueled power plants

EPA relies on an industry cooling tower cost spreadsheet developed by the Electric Power Research Institute (EPRI) to estimate cooling tower costs in the 2011 TDD. Reliance on the EPRI cost spreadsheet is problematic for two reasons: 1) EPRI can not be considered a neutral party in assessing the cost or difficulty of cooling tower retrofits, given EPRI member companies have consistently opposed such retrofits, and 2) the EPRI cost spreadsheet produces substantially higher costs than the well-documented EPA cooling tower cost model developed for the same purpose.

Unlike the EPRI cost spreadsheet used by EPA in the 2011 TDD, the inputs to the cooling tower cost model developed by EPA and used in the 2002 TDD are thoroughly explained and corroborated with actual fossil and nuclear plant retrofit cost data. EPA also provides the cost of actual cooling tower retrofits in Chapter 4 of the 2002 TDD. However, EPA sets aside its reasonably accurate cooling tower cost model in favor of the EPRI cost spreadsheet, which estimates substantially higher cooling tower capital and operating costs, in the 2011 TDD.

A. Wet inline cooling tower capital cost: The EPRI cost spreadsheet adopted by EPA, with no supporting documentation, produces wet inline cooling tower capital costs that are 45 percent greater than the value produced by the EPA cost model

EPA relies exclusively on an EPRI cost spreadsheet model for determining cooling tower capital and O&M cost. EPA states:[1]

> In September 2007, EPA obtained an Excel spreadsheet from EPRI that contained a set of calculations for estimating cooling tower retrofit costs at existing steam power plants. EPA compared the EPRI model to the methodology used in the Phase II NODA and found that the two methods produced similar costs. Because these methods produced similar costs and the EPRI method was simpler and more flexible, the EPRI methodology was chosen to develop the model facility cost equations for the proposed rule.

EPA also provides brief background information on the EPRI spreadsheet model and notes that other studies were also reviewed:[2]

> The EPRI tool calculated costs based on documentation for over 50 closed-cycle retrofits and detailed feasibility studies. EPA also used cooling tower engineering assessments conducted for California as part of the Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling. These detailed assessments were conducted on 19 existing coastal plants. Maulbetsch and others have documented cooling tower assessments and presented such findings in symposiums and proceedings; for example see "Issues Associated with Retrofitting Coastal Power Plants" (DCN 10-6955) and "Water Conserving Cooling Status and Needs" Energy-Water Needs" (DCN 10-6953).

Finally, EPA explains the basis for its assertion that the EPRI cooling tower cost methodology produces a similar result to the methodology used by EPA in the Phase II NODA:[3]

> Exhibit 12-2 provides a comparison of the wet inline cooling tower compliance costs derived using the EPRI Tower Calculation Worksheet to compliance costs derived using the EPA Methodology used in 2004 Phase II for an option where cooling towers were retrofitted to facilities on estuaries and oceans.
>
> Exhibit 12-3 shows that the two costing methodologies produce similar results. While the 2004 EPA non-nuclear and nuclear facility capital costs are comparable to the EPRI "easy" and "average" costs, the EPA's O&M cost are higher for nuclear facilities.

[1] 2011 TDD, p. 8-15.
[2] Ibid, p. 12-6.
[3] Ibid, p. 12-7.

Exhibit 12-3. Cost Comparison for a 350 MW Plant with Cooling Flow of 200,000 gpm (288 MGD)

	Tower Type	Capital Costs - Tower and Piping	Condenser Upgrade[1]	O&M	Tower Electricity Usage (Pumps & Fans)	O&M Total[2]	Annualized Capital Not Including Condenser Upgrade[3]	Annualized Condenser Upgrade	Total Annualized Cost Not Including Condenser Upgrade	Annual Heat Rate Penalty[4]
EPA Phase II	Redwood Tower	$27,000,000	$5,200,000	Included in O&M Total	Included in O&M Total	$2,900,000	$2,200,000	$400,000	$5,100,000	?
	Redwood Tower - Nuclear	$49,000,000	$9,400,000	Included in O&M Total	Included in O&M Total	$4,200,000	$3,900,000	$800,000	$8,100,000	?
EPRI Costs	Easy	$32,000,000	-	$260,000	$2,600,000	$2,860,000	$2,600,000	-	$5,460,000	$1,040,000
	Average	$53,000,000	-	$260,000	$2,600,000	$2,860,000	$4,200,000	-	$7,060,000	$1,040,000
	Difficult	$83,000,000	-	$260,000	$2,600,000	$2,860,000	$6,600,000	-	$9,460,000	$1,040,000

[1] EPA did not include full condenser upgrade costs at all facilities. Not sure If EPRI included them

The average EPA capital cost for a non-nuclear plant wet inline redwood tower is shown as $27 million in EPA Exhibit 12-3. This is an average cost based on the retrofit cost adder of 20 percent assumed by the EPA. EPA identifies the cost for the redwood tower at a nuclear plant as $49 million. EPRI does not distinguish between the cost of a cooling tower at a non-nuclear plant or a nuclear plant. The EPRI average retrofit cost for the same 200,000 gpm case, whether non-nuclear or nuclear, is $53 million. EPRI also identified the unit cost for an inline wet cooling tower retrofit as $263/gpm.[4]

EPA provides no specific information in the March 2011 TDD on why the agency assumes that cooling tower retrofit costs at a nuclear plant should be nearly double the cost of retrofits at non-nuclear plants for the same size cooling tower.

EPA does provide an example calculation of its cooling tower model cost calculation procedure in the 2002 TDD for a fossil plant with a total circulating cooling water flowrate of 416,667 gpm (pp. 2-32 to 2-36). The total capital cost of the cooling tower retrofit, including a 20 percent retrofit premium and 1.08 labor rate multiplier for a high labor cost region, was estimated by the EPA as $53.55 million. The EPA estimated an additional cost of $1.955 million for intake and discharge piping modifications. This equals a total cooling tower retrofit cost, assuming inline redwood wet towers, of $55.5 million.

An adjustment to the EPA model cost is necessary to account for the rise in costs between 1999 and 2009. The rise in costs is on the order of 37 percent between 1999 and 2009.[5] The unit EPA inline redwood cooling tower retrofit cost, adjusted to 2009, would be $182/gpm, as shown in Table 1. The EPRI spreadsheet estimates an average in-line cooling tower retrofit capital cost that is approximately 45 percent higher than the cost estimated by the EPA model for the same

[4] March 2011 TDD, Exhibit 8-6, p. 8-18.
[5] Chemical Engineering, *Economic Indicators – Marshall & Swift Equipment Cost Index, Annual Index*, January 2006 and January 2011 editions, p. 68 and p. 60, respectively. Annual Index in 1999 = 1,068.3. Annual Index in 2009 = 1,468.6. Rise in equipment cost between 1999 and 2009: (1,468.6 – 1,068.3)/1,068.3 = 0.3747 (37 percent).

cooling tower retrofit, $263/gpm versus $182/gpm, when the cost estimates are normalized to the same year.[6]

Table 1. EPA Cost Estimate for Standard Wet In-Line Cooling Tower

Cooling tower type	Flowrate (gpm)	Cooling tower retrofit capital cost[7] ($)	Intake/ discharge piping modifications ($)	Inflation multiplier, 1999 - 2009	2009 EPA retrofit cooling tower capital cost ($)	2009 EPA retrofit cooling tower capital cost ($/gpm)
wet, inline, redwood, fresh water	417,000	53.55	1.955	1.37	76	182

The EPRI spreadsheet cost estimate is high relative to cooling tower manufacturer estimates as well as the EPA estimate. SPX is the largest manufacturer of power plant cooling towers in the U.S. SPX provided Powers Engineering with a generic capital cost estimate for wet back-to-back cooling towers and plume-abated back-to-back cooling towers for nuclear plant applications in 2009. Back-to-back cooling towers are much more space efficient than the in-line, single cell width tower design assumed by EPA in the March 2011 TDD. A back-to-back tower design would be the likely cooling tower choice at space-constrained sites. SPX assumed a cooling tower design approach temperature of 12 ^{o}F and a design range of 20 ^{o}F. The SPX back-to-back cooling tower capital cost information is summarized in Table 2 and is provided as **Attachment A** to this comment letter.

The EPRI cost spreadsheet adopted by the EPA assumes, in addition to an average wet cooling tower retrofit cost of $263/gpm, an average plume-abated cooling tower retrofit cost of $383/gpm.[8] The EPRI composite wet cooling tower retrofit cost, assuming 75 percent of cooling tower retrofits are inline wet towers and 25 percent are plume-abated inline wet towers, is $293/gpm.[9]

[6] EPA in-line retrofit tower cost + piping modifications: $55,500,000/416,667 gpm = $133/gpm. Inflation adjustment: 1.37 × $133/gpm = $182/gpm. EPRI spreadsheet capital cost estimate, average retrofit: $263/gpm . EPRI spreadsheet estimate is about 45 percent higher than adjusted EPA estimate: $263/gpm ÷ $182/gpm = 1.49.
[7] SPX states in its June 2009 cost estimate that "Infrastructure cost is estimated by some at 3 times the cost of the wet tower, including such things as site prep, basins, piping, electrical wiring and controls, etc." Therefore, the total capital cost of the wet back-to-back tower in a fresh water application is the "wet tower only" cost of $36.4 million + (3 × $36.4 million) = $145.6 million.
[8] March 2011 TDD, Exhibit 8-7, p. 8-18.
[9] Ibid.

Table 2. Summary of SPX June 2009 Cost Estimate for Wet and Plume-Abated Back-to-Back Cooling Towers, 12 ^{o}F Approach Temperature, 20 ^{o}F Range

Cooling tower type	Flowrate (gpm)	Capital cost[10] ($)	Unit cost ($/gpm)	EPA retrofit multiplier	Capital cost including retrofit multiplier	
					($)	($/gpm)
standard wet, back-to-back, fresh water	830,000	145.6	175	1.20	175	210
plume-abated, back-to-back, fresh water	830,000	218.3	263	1.20	262	316
standard wet, back-to-back, salt water	830,000	154.4	186	1.20	185	223
plume-abated, back-to-back, salt water	830,000	231.4	279	1.20	278	335

B. EPA cooling tower sizing 10 ^{o}F design approach temperature is conservative for most regions of the country, which lead to conservative estimates of capital cost

The EPA cooling tower cost model assumes a relatively conservative approach temperature of 10 ^{o}F. EPA lists “Maulbetsch and others” as a source of cooling tower cost reference material in the 2011 TDD.[11] Maulbetsch identifies a cooling tower approach range of 8 to 15 ^{o}F and states that, in general, warmer, more humid conditions lead to lower approach temperatures in the southeastern U.S. and cooler, drier climates lead to higher approach temperatures in the northern and western regions.[12] At any particular site, a lower approach temperature translates into a larger and more costly the cooling tower, as EPA notes in the 2002 TDD:[13]

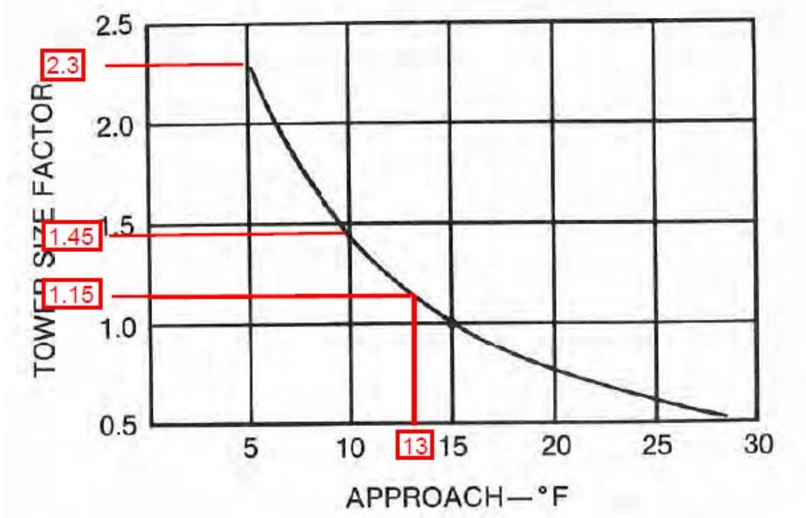
> Two cooling tower industry managers with extensive experience in selling and installing cooling towers to power plants and other industries provided information on how they estimate budget capital costs associated with a wet cooling tower. The rule of thumb they use is $30/gpm for an approach of 10 degrees and $50/gpm for an approach of 5 degrees.

EPA’s use of 10 ^{o}F as the assumed approach temperature in the cooling tower cost model is a very conservative assumption for most parts of the country. The 2002 TDD Appendix A list of

[10] SPX states in its June 2009 cost estimate that “Infrastructure cost is estimated by some at 3 times the cost of the wet tower, including such things as site prep, basins, piping, electrical wiring and controls, etc.” Therefore, the total capital cost of the wet back-to-back tower in a fresh water application is the “wet tower only” cost of $36.4 million + (3 × $36.4 million) = $145.6 million.
[11] Ibid, p. 12-6.
[12] J. Maulbetsch, *Comparison of Alternate Cooling Technologies for California Power Plants - Economic, Environmental and Other Tradeoffs*, CEC Consultant Report, February 2002, pp. 2-8 and 2-9. “Tower approach, $T_{cold\ water} - T_{ambient\ wet\ bulb}$: 8 to 15 ºF. In general, warmer, more humid conditions lead to lower approach temperatures in the southeastern U.S. and cooler, drier climates lead to higher ones in the northern and western regions.”
[13] April 2002 TDD, p. 2-20.

specifications for actual cooling towers lists fifteen towers at or above a flowrate of 100,000 gpm.[14] Six of these towers are located in the Southeast. Nine towers are located in other parts of the country. The average approach temperature of the six cooling towers in the Southeast is 8.7 °F. The average approach temperature of the nine cooling towers located in other parts of the country is 12.6 °F. Figure 1 shows the effect of cooling tower design approach temperature on the size of the cooling tower.

Figure 1. Cooling Tower with 10 °F Approach Temperature Is 25 Percent Larger than Tower with 13 °F Approach Temperature[15]



For the purpose of calculating the nationwide cost of plume-abated cooling towers, it is assumed in this comment letter that 25 percent of the plume-abated cooling tower retrofits would occur in the Southeast and would be designed for a 8 °F approach temperature. Cooling towers for other areas of the U.S. would be designed for a 12 °F approach temperature. Cooling towers in the Southeast would be about 30 percent larger than cooling towers in the rest of the country for the same circulating water flowrate, as determined in **Attachment B**. All of the plume-abated units are assumed to utilize a compact, back-to-back design.[16]

From Table 1, the unit cost of back-to-back plume-abated cooling tower with a 12 °F design approach temperature is $316/gpm. Decreasing the design approach temperature to 8 °F would increase the capital cost by about 30 percent to: $316/gpm × 1.3 = $411/gpm.

The composite nationwide capital cost of plume-abated back-to-back cooling towers, assuming 75 percent have a design approach temperature of 12 °F and 25 percent have an approach temperature of 8 °F is: (0.75 × $316/gpm) + (0.25 × $411/gpm) = $340/gpm.

[14] April 2002 TDD, Attachment C to Chapter 5: *Design Approach Data for Recent Cooling Tower Projects*. The 100,000 gpm cooling tower circulating water flowrate threshold represents larger fossil fuel and nuclear units approximately 200 MW and up.
[15] SPX Cooling Technologies, *Cooling Tower Fundamentals*, 2nd Edition, 2006, p. 23. Red tags and lines added by B. Powers.
[16] This assumption is made to simplify cost calculations. The final mix of cooling towers could include wet back-to-back cooling towers and inline plume-abated cooling towers.

C. *Unlike the EPRI cost spreadsheet, the non-fossil fuel EPA cooling tower cost model inputs in the 2002 TDD are thoroughly explained and corroborated with actual fossil and nuclear plant retrofit cost data*

EPA provides extensive detail on the cooling tower cost model presented in the 2002 TDD. EPA also provides the cost of actual cooling tower retrofits in Chapter 4 of the 2002 TDD. The costs of these actual cooling tower retrofits are summarized in Table 3.

Table 3. Cost of Closed-Cycle Retrofits at Selected U.S. Sites

Site	MW	Flowrate (gpm)	Cost of Retrofit[a]		
			($MM)	($/kW)	($/gpm)
Palisades Nuclear	800	410,000	55.9	70	136
Pittsburg Unit 7	751	352,000	34.4	46	98
Yates Units 1-5	550	460,000	87.0[b]	158	189
Canadys Station	490		Not available[c]		
Jeffries Station	346		Not available[c]		

a) Retrofit costs for Palisades Nuclear and Pittsburg Unit 7 are in 1999 dollars. Yates 1-5 cooling tower cost is in 2002 dollars.
b) The Yates cooling tower is designed to achieve a 6 ^{o}F approach temperature. Original estimate $75 million. Revised $87 million cost includes wetland remediation, remediation of old asbestos landfill where towers were to be constructed, and reinforcement of concrete cooling water conduits.
c) The U.S. Army Corps of Engineers (COE) paid for the cooling tower retrofit. COE diversion of riverwater was the reason that the retrofit needed to be carried out.

The EPA specifically notes in the 2002 TDD that the cooling tower retrofit cost model it developed was very accurate, especially for the Palisades Nuclear plant, stating (p. 2.23):

> As described in Chapter 4, the Agency obtained two empirical, total project costs for cooling tower conversion projects. The Agency calculated estimated project costs based on the methodology presented in Example 2 below and determined that for the case of the Palisades conversion that the Agency's methodology was very accurate.

In Example 2 of the 2002 TDD, EPA calculated the cost of the conversion of a plant to a cooling tower with a flowrate of 417,000 gpm and a 10° F approach temperature. The cost of the cooling tower and piping upgrades was calculated as $55.5 million (assuming 20 percent retrofit cost premium and 1.08 labor premium).[17] This equals a cost per gpm cost of: $55,500,000/ 417,000 gpm = $133/gpm (1999 dollars). A cost of $8,744,600 was identified for the surface condenser upgrade. This cost includes a charge for the premature retirement of the existing surface condenser. EPA calculated a retrofit cost with a full condenser upgrade of $64,245,000. The cost per gpm = $64,245,000/417,000 gpm = $154/gpm (1999 dollars).

The EPA cooling tower cost model is conservative, as it assumes larger closed cycle cooling flows than are specified for actual closed cycle installations. This means that the model cooling tower fan energy and pump energy requirements are also conservative. The EPA states:[18]

[17] April 2002 TDD, p. 2.32.
[18] Ibid, p. 2-18.

> Published condenser flows and generating capacity data from the Nuclear Regulatory Commission (DCN 4-2521)) for all nuclear units in the US demonstrates that recirculating cooling systems have lower condenser flow to MW ratios than once through systems, regardless of age or other characteristics. After considering this information, EPA chose a conservative approach and used the design cooling water intake flow of the baseline once-through system intake to estimate the size of the recirculating cooling tower and associated conduit system for its model facilities.

The EPA model is also very conservative in asserting a surface condenser upgrade cost of $8.7 million dollars for a circulation rate of 417,000 gpm. Thermal Engineering International, Inc. (TEI) is a leader in surface condenser upgrades.[19] TEI estimated a cost of $600,000 to replace the tube bundle and waterboxes on 235 MW Danskammer Unit 4 in 2005.[20] The Danskammer plant is located on the Hudson River. Unit 4 is designed for a circulating cooling water flowrate of 150,000 gpm.[21] A linear scale-up of this surface condenser upgrade cost estimate, for a 417,000 gpm circulating cooling water flowrate, would be: ($600,000 x 417,000 gpm/150,000 gpm) = ~$1.7 million. This is approximately one-fifth the cost that EPA attributes to the surface condenser upgrade for a flowrate of 417,000 gpm in the 2002 TDD.

The EPA also fails to note in the 2002 TDD that a surface condenser upgrade typically results in about a 0.5 percent efficiency improvement over original equipment.[22] This performance improvement would significantly offsets the efficiency reduction associated with the cooling tower retrofit.

D. EPA's March 2011 TDD repeats the same errors in 2002 TDD regarding cost premium to retrofit cooling towers at nuclear plants

The EPA cooling tower cost model, without the inclusion of cost premiums for nuclear safety-related issues such as blasting restrictions near operating reactors, was confirmed by the agency as conservative and reasonably accurate for both fossil fuel plant retrofits and nuclear plant retrofits (Palisades Nuclear) in the 2002 TDD.

Despite confirming in Example 2 in the 2002 TDD that the EPA cost model is accurate for fossil fuel and nuclear plants without cost premiums for nuclear plant construction activities,[23] in the

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[19] See TEI webpage on surface condenser upgrade projects: http://www.babcockpower.com/products/heat-exchangers/thermal-engineering/products/surface-condensers#more-1.
[20] Telephone communication, P. Luhring/Thermal Engineering International, and B. Powers/Powers Engineering, September 16, 2005.
[21] New York Department of Environmental Conservation, *Danskammer Point Generating Station Biological Fact Sheet*, 2003, p. 1. Unit 4 has three cooling water pumps rated at 50,000 gpm each.
[22] Telephone communication, P. Luhring/Thermal Engineering International, and B. Powers/Powers Engineering, September 16, 2005. P. Luhring – Typical gain on a 500 MW unit is 2-3 MW with tube bundle replacement. This is a 0.5 percent efficiency improvement over original equipment. The project scope would include tubes, tubesheets, and support plants. TEI prefers to replace waterboxes with the tube bundle replacement to ease alignment.
[23] 2002 TDD, p. 2-23. "The Agency calculated estimated project costs based on the methodology presented in Example 2 below and determined that for the case of the Palisades conversion that the Agency's methodology was very accurate."

same document EPA identifies substantial cost multipliers for retrofit work at nuclear plants. The agency provides no references to support these multipliers. For example, the 2002 TDD states:[24]

> "Intake modification construction costs are based on the following general framework: . . . Also, EPA doubled costs of demolition and excavation (at nuclear plants) to account for concerns that use of blasting and high-impact equipment may be limited at nuclear facilities."

EPA assigns a 1.58× nuclear plant multiplier in the 2002 TDD with no supporting documentation.[25] EPA states in the 2011 TDD that it considered a wide variety of technical aspects associated with retrofitting cooling towers, including (but not limited to) the availability of land, noise and plume effects, evaporative losses, and nuclear safety concerns.[26] However, the only additional information given in the document regarding nuclear safety issues contradicts the presumption that retrofitting cooling towers at a nuclear plant would add cost relative to a retrofit at a fossil plant. Specifically, the EPA states:[27]

> While nuclear safety remains a paramount concern, it is less clear that retrofitting a cooling tower would actually have any impact on the safety of the facility. Documentation submitted to the Atomic Energy Commission from Palisades Plant (the lone nuclear facility to undergo a closed-cycle retrofit) indicates that "[t]he existing cooling water system […] has no safety related functions and the modified system will likewise have no safety related functions." See DCN 10-6888B.

EPA states qualitatively that nuclear retrofit cost is driven up in part due to nuclear safety concerns, yet points-out that the predecessor agency to the NRC, the Atomic Energy Commission, indicates there are no safety concerns related to cooling tower retrofits at nuclear plants.

There is no inherent safety issue with nuclear plants operating as exclusively closed-cycle units, or as combination units capable of operating either in closed cycle mode or in OTC mode. The 2011 TDD points-out that 23 U.S. nuclear plants use closed cycle cooling, 8 have combination closed cycle/OTC capability, and 31 are OTC plants.[28] EPA also notes that a somewhat larger percentage of nuclear facilities use closed-cycle cooling than non-nuclear facilities.[29] Cooling towers are common at U.S. nuclear plants.

EPA presents no documentation in the 2002 TDD, the 2003 Phase II NODA, or the 2011 TDD to support its contention that the cost of cooling tower retrofits at nuclear plants is substantially higher than at fossil fuel plants. In contrast, the EPA does summarize the position of the NRC predecessor agency, the Atomic Energy Commission, that there are no safety issues associated with the cooling tower retrofit at the one U.S. nuclear plant that has been retrofit with cooling towers, Palisades Nuclear in Michigan. None of the qualitative concerns expressed by EPA,

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[24] Ibid, p. 2-2 and 2-3.
[25] Ibid, p. 2-35.
[26] 2011 TDD, p. 2-23.
[27] Ibid, p. 6-9.
[28] Ibid, p. 4-9: Exhibit 4-10, *Types of cooling systems at US nuclear plants*.
[29] Ibid, p. 5-4, Exhibit 5-5.

which are used by the agency as the basis for adding considerable extra cost to retrofitting cooling towers at nuclear plants, are supported in the record.

E. The EPRI composite cooling tower retrofit cost adopted by EPA in the March 2011 TDD, including wet and plume-abated inline cooling towers, is over 30 higher than the composite cooling tower cost calculated using EPA and industry cost estimates

The composite nationwide unit cost for cooling tower retrofits using the EPA cost estimate for wet inline cooling towers and the SPX cost estimate for plume-abated back-to-back cooling towers is: (0.75 × $182/gpm) + (0.25 × $340/gpm) = $222/gpm. The composite nationwide unit cost for average difficulty cooling tower retrofits developed by EPRI and adopted by EPA of $293/gpm is 32 percent higher than the estimate based on EPA and SPX cost estimates.[30]

II. Reasonableness of EPA's estimate of turbine efficiency penalty and cooling tower parasitic fan and pump loads for nuclear and fossil plants

A. The EPRI cost spreadsheet adopted by EPA with no supporting documentation produces a turbine efficiency penalty that is approximately 5x the EPA cost model annual average turbine efficiency penalty and 10x the turbine efficiency penalty identified by the EPA for the Jefferies coal plant cooling tower retrofit

The 2011 TDD summarizes the EPRI cost spreadsheet factors the EPA has adopted for use in Exhibit 8-6:[31]

Exhibit 8-6. Cooling Tower Costs for Average Difficulty Retrofit

Costs and Generating Output Reduction	Equation	Constant (2009)
Capital Cost (CC)	CC = MRIF(gpm) x Constant	$263
Fixed O&M Cost (OMF)	OMF = MRIF(gpm) x Constant	$1.27
Variable O&M - Chemicals (OMC)	OMC= MRIF(gpm) x Constant	$1.25
Variable O&M - Pump & Fan Power (OMV)	OMV= MRIF(gpm) x Constant	0.0000237
Energy Penalty -Heat Rate (EP) Non-nuclear	EP=MWS[a] x Constant	0.015
Energy Penalty -Heat Rate (EP) Nuclear	EP=MWS x Constant	0.025

[a] MWS is the total steam generating capacity in MW.

The EPRI cost spreadsheet summarized in Exhibit 8-6 assigns a turbine efficiency penalty of 1.5 percent to fossil fuel plants and 2.5 percent to nuclear plants.

In an effort to demonstrate that the EPRI turbine efficiency penalty estimates are accurate, EPA misstates the turbine efficiency penalty caused by a cooling tower retrofit:[32]

> The turbine efficiency penalty is typically expressed as a percentage of power output. In the Phase I Rule, EPA estimated an annual average energy penalty of 1.7 percent for nuclear and fossil-fuel plants and 0.4 percent for combined cycle plants. The estimated maximum summer penalty was 1.9 percent. The EPRI supporting documentation (DCN 10-6930)

[30] $293/gpm ÷ $222/gpm = 1.32 (32 percent).
[31] March 2011 TDD, , p. 8-18, Exhibit 8-6: *Cooling Tower Costs for Average Difficulty Retrofit*.
[32] March 2011 TDD, p. 8-25.

estimates the energy penalty to range between 1.5 percent and 2.0 percent, and the EPRI cost model uses 2.0 percent as the built-in default.

In this statement, EPA confuses the peak turbine efficiency penalty with the annual average total energy penalty, which includes annual average turbine efficiency, cooling tower fan and pump energy demand. Both the 2001 Phase I TDD and the 2002 TDD included the average heat rate penalty, fan penalty, and pump penalty for nuclear, fossil fuel, and combined cycle plants. The average annual turbine efficiency penalty data is presented in Table 4 below. As shown in Table 3, the peak turbine efficiency penalty produced by its model is substantially lower than the average turbine efficiency penalties included in the EPRI cost spreadsheet. The average turbine efficiency penalties calculated using the EPA model, and corroborated at both coal and nuclear plants that have been retrofit with cooling towers, are on the order of one-fifth the values calculated with the EPRI cost spreadsheet.

Table 4. EPA Cost Model – Annual Average and Peak Turbine Efficiency Penalty[33]

Plant Type	Average Turbine Efficiency Penalty (%)	Peak Turbine Efficiency Penalty (%)
Nuclear	0.40	1.03
Fossil Fuel	0.35	0.90
Combined Cycle	0.06	0.19

The turbine efficiency penalties shown in Table 3 are reasonably accurate, based on detailed efficiency penalty analyses for two coal-fired plants and one nuclear plant. The first is the 346 MW Jeffries Generating Station in South Carolina. A summary of this analysis was included in the 2002 TDD (p. 5-34). The second is the Powers Engineering analysis of the turbine efficiency penalty that would be incurred by retrofitting 235 MW coal-fired Danskammer Unit 4 to a plume-abated wet cooling tower.[34] This analysis is included as **Attachment C** to this comment letter. Danskammer Unit 4 is cooled with water from the Hudson River.

The EPA identifies the annual average turbine efficiency penalty of the 10 °F approach temperature Jefferies cooling tower retrofit as 0.16 percent and the peak efficiency penalty as 0.90 percent, stating:

> "The Jefferies Generating Station – a 346 MW, coal-fired plant in South Carolina – owned by Santee Cooper, conducted a turbine efficiency loss study in the late 1980s. The study lasted several years (1985 to 1990). The efficiency penalties determined by Santee Cooper were a maximum of 0.97 percent of plant capacity (for both units, combined) and an annual average of 0.16 percent for the year 1988. The Agency notes that its fossil-fuel estimate for the national-average, peak-summer, turbine energy penalty is 0.90 percent and the mean-annual, national-average energy penalty is 0.35 percent (at 100 percent of maximum load)."

[33] 2001 Phase I TDD, Table 3-14, p. 3-20, and 2002 TDD, Table 5-10, p. 5-20.

[34] Rebuttal Testimony of William Powers, P.E. on Behalf of Petitioners Riverkeeper, Inc., Scenic Hudson Inc. and Natural Resources Defense Council, Inc., NYDEC - In The Matter of a Renewal and Modification of a State Pollutant Discharge Elimination System ("SPDES") Permit SPDES No. NY-0006262 by Dynegy Northeast Generation, Inc., on Behalf of Dynegy Danskammer, LLC (Danskammer Generating Station), November 7, 2005, Exhibit 11.

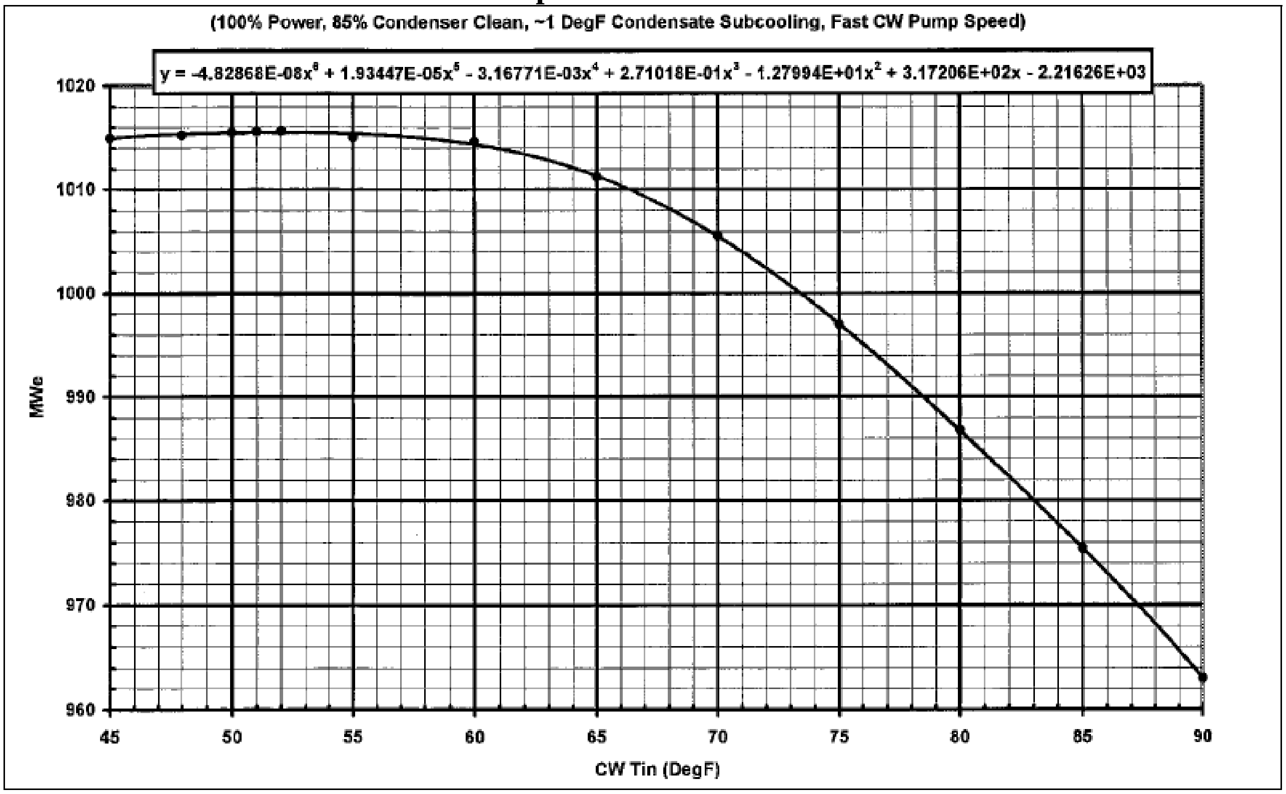
> p. 4-2: “The Agency contacted Santee Cooper to learn about the cooling system conversions at Jefferies (Henderson, 2002). The Charleston District of the U.S. Army Corps of Engineers paid for the construction of the tower system (a common, mechanical-draft, concrete cooling tower unit for both units with a design approach of 10 °F and a range of 19 °F) because of the re-diversion of the Santee Cooper River.”

The coal-fired Danskammer Unit 4 cooling tower retrofit analysis assumed use of a plume-abated cooling tower with a 13 °F approach temperature and 20 °F range. The annual average turbine efficiency penalty of the cooling tower relative to the existing once through cooling configuration was calculated to be approximately 0.2 percent. The peak turbine efficiency penalty was calculated to be approximately 1.5 percent.[35] The reason for the small annual average turbine efficiency penalty is that the Hudson River increases to over 80 °F in summer, which increases backpressure on the turbine.

This phenomenon is shown in Figure 2 for Unit 2 at the Indian Point Nuclear Generating Station (Indian Point). The output of Indian Point Unit 2 drops from 1,015 MW at a river temperature of 55 °F to 983 MW at 82 °F. This is a 3.4 percent drop in output due to the turbine efficiency penalty experienced by the existing OTC cooling system as the river temperature rises to its maximum monthly level.

[35] Ibid.

Figure 2. Reduction in MW Output from Indian Point Nuclear Unit 2 as Hudson River Temperature Increases[36]



The owner of Indian Point, Entergy Nuclear, determined the month-to-month turbine efficiency penalty of a cooling tower conversion on MW output from Indian Point Units 2 in its analysis of the feasibility and cost of such a conversion.[37] Powers Engineering has overlaid curves showing the decline in MW output of the existing OTC-cooled Units 2 and 3 caused by increasing Hudson River water temperature on the cooling tower turbine efficiency penalty curves prepared by Entergy Nuclear.[38] This data is presented in **Attachment D**.

The average annual turbine efficiency penalty that would be imposed on Indian Point Unit 2 by a cooling tower conversion would be approximately 5 MW, or approximately 0.5 percent. The average annual turbine efficiency penalty imposed on Indian Point Unit 3 by a cooling tower conversion would be approximately 2 MW, or approximately 0.2 percent. See Tables D-1 and D-

[36] Enercon, *Conversion of Indian Point Units 2 & 3 to a Closed-Loop Cooling Water Configuration, Attachment 1- Economic and Environmental Impacts Associated with Conversion of Indian Point Units 2 and 3 to a Closed-Loop Condenser Cooling Water Configuration*, June 2003, p. 21.
[37] Ibid, Figures 3-7 and 3-8, p. 24.
[38] Hudson River monthly average temperature data is taken from Attachment C. This river water temperature data was collected at the Danskammer Generating Station approximately 20 miles upriver from Indian Point. The monthly river water temperature is applied to the "river water temperature versus MW output" curves provided by Entergy Nuclear consultant Enercon in its June 2003 report "*Conversion of Indian Point Units 2 & 3 to a Closed-Loop Cooling Water Configuration, Attachment 1- Economic and Environmental Impacts Associated with Conversion of Indian Point Units 2 and 3 to a Closed-Loop Condenser Cooling Water Configuration*."

2 in **Attachment D**. The average annual turbine efficiency penalty of both Indian Point Unit 2 and Unit 3, approximately 0.4 percent, is consistent with the EPA determination in the 2002 Phase II TDD that the average turbine efficiency penalty imposed by a cooling tower conversion at a nuclear plant would be 0.40 percent.

EPA also determined the peak and annual average total energy penalty for the cooling tower conversion at the Palisades Nuclear Plant in Michigan as 2.7 percent and 1.8 percent respectively, stating:[39]

> The Agency learned from discussions with, and information submitted by, Consumers Energy that the cooling tower system at Palisades might have a significant impact on the efficiency of the plant's generating unit. . . Therefore, the Agency estimates that the total energy penalty of the recirculating tower system at Palisades may have a peak energy penalty close to 2.7 percent and an annual penalty approaching 1.8 percent as compared to the original once-through system (Sunda, et al., 2002).
>
> Based on the Agency's energy penalty methodology, the turbine energy penalty for a nuclear unit (at peak summer conditions) would be approximately 1.4 percent (11.3 MW for Palisades). The Agency calculated this penalty using the historic cooling water temperature data for Palisades provided by Consumers Energy and ambient dry bulb and wet bulb air temperatures specific to Chicago, IL (Consumers, 2001).

The annual average total energy penalty of 1.8 percent for Palisades is consistent with the EPA cost model presented in the 2002 TDD, which calculates a total cooling tower retrofit energy penalty for a nuclear plant of just over 1.5 percent (see Table 5).

EPA shifts from using the annual average turbine efficiency penalty in the 2002 TDD, which is the appropriate measure of net electricity not delivered to the grid over time by a cooling tower conversion, to using peak turbine efficiency penalty in the 2003 Phase II NODA. The use of peak turbine efficiency is also carried into the 2011 TDD. This shift is described in the 2003 Phase II NODA in the following manner:[40]

> *Energy Penalties* For the proposed Phase II rule, the average annual energy penalty, by region and fuel type, was applied to each facility upgrading to a closed cycle, recirculating cooling system. Based on comments received, EPA has changed the energy penalty assumption to attempt to account for seasonal, peak effects. For the new analyses, the energy penalty applied is the greater of the peak-summer penalty or the average annual penalty for each facility projected to convert their cooling systems to a closed-cycle, recirculating cooling system. EPA notes that the approach used at proposal might have understated potential impacts of the energy penalty on generating capacity.
>
> Conversely, using the greater of the peak summer penalty and the average annual penalty might overestimate potential impacts of the energy penalty on generating capacity. EPA has adopted the latter approach in order to ensure that impacts are not underestimated.

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[39] 2002 TDD, p. 5-36 and p. 5-37.
[40] Phase II NODA, Federal Register /Vol. 68, No. 53 /Wednesday, March 19, 2003 / Proposed Rules FR 13525.

What matters from a cost of replacement power and air emissions standpoint is the annual average turbine efficiency penalty, not the peak. The change by EPA from use of the annual average total energy penalty to the peak energy penalty was an error. It is also an error in the EPRI model. Peak output reductions caused by use of retrofit cooling towers are significant only to the extent that insufficient reserve margin is available to assure continuity of service during peak demand periods.

Also, grid operators are constantly going out for bid for new capacity to assure that reserve margins in excess of grid reliability requirements are maintained. For example, PJM just accepted bids for more than 4,800 MW of demand response capacity to meet projected reserve margin requirements.[41] For this reason, the slight peak demand reduction caused by the installation of retrofit cooling towers will not impact grid reliability.

B. *The EPRI cost spreadsheet adopted by EPA produces cooling tower fan and pump parasitic loads that are about 30 percent higher than the values produced by the EPA cost model*

The 2002 TDD includes the average cooling tower fan energy penalty and pump energy penalty for nuclear, fossil fuel, and combined cycle plants. The EPA cooling tower fan and pump energy penalties are presented in Table 5. The average fan power penalty assumed in the 2002 TDD is incorrect, as it is for a cooling tower with a 5 $^{\circ}$F approach temperature. The EPA cost model assumes a cooling tower with a 10 $^{\circ}$F approach temperature. Use of the 10° F cooling tower fan power penalty from the same EPA dataset reduces the fan energy penalty. The correct fan penalty for a 10° F approach cooling tower is provided in Table 4. Table 4 also includes the combined fan and pump energy penalty calculated using the EPRI cooling tower fan and pump energy penalty factor for the same cooling tower case.

As shown in Table 6, the annual average total energy penalty calculated for nuclear plants using the EPA cost model, at 1.51 percent, is substantially lower than the turbine efficiency penalty of 2.5 percent the EPRI cost spreadsheet assumes for nuclear plants. The annual average total energy penalty for fossil fuel plants using the EPA cost model, at 1.24 percent, is lower than the turbine efficiency penalty of 1.5 percent the EPRI cost spreadsheet assumes for fossil fuel plants.

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[41] Public Utilities Fortnightly, *Up in smoke: demand response knocks 6.9 GW of coal out of PJM,* June 29, 2011.

Table 5. Comparison of EPA and EPRI Cost Model Outputs Assuming 525 MW Plants–Cooling Tower Pump and Fan Power Penalty

Plant Type	EPA Model				EPRI Model
	Pump power energy (%)	Fan power energy (%)[42]	Total pump and fan power energy (%)	Total pump and fan power energy (MW)	Total pump and fan power energy (MW)[43]
Nuclear	0.55	0.56	1.11	5.6	7.2
Fossil Fuel	0.44	0.45	0.89	4.5	5.8
Combined Cycle	0.15	0.15	0.30	1.5	1.9

Table 6. EPA Cost Model – Annual Average and Peak Total Energy Penalty

Plant Type	Annual Average Penalty (%)			
	Turbine efficiency	Fan power energy[44]	Pump power energy	Total Energy Penalty
Nuclear	0.40	0.56	0.55	1.51
Fossil Fuel	0.35	0.45	0.44	1.24
Combined Cycle	0.06	0.15	0.15	0.36

The EPA cooling tower cost model provides reasonably accurate estimates of annual average turbine efficiency penalty, fan energy demand, and pump energy demand. The EPRI cost spreadsheet substantially overestimates the turbine efficiency penalty and moderately overestimates the fan and pump energy requirements. EPA should continue to use efficiency

[42] EPA model cooling tower costs are based on a cooling tower with a 10 ^oF approach temperature. EPA identifies representative fan power energy penalties in Table 5-12 of the 2002 TDD for four sample plants. The fan power energy penalties shown are for Plant #3 using a cooling tower with an approach temperature of 10 ^oF and a flowrate of 243,000 gpm. None of the other cooling towers in Table 5-12 have an approach temperature of 10 ^oF. Table 5-15 of the 2002 TDD, *Summary of Fan and Pumping Energy Requirements as a Percent of Power Output*, incorrectly uses the fan power energy penalty for a 5 ^oF approach cooling tower and not the design 10 ^oF approach cooling tower assumed in the EPA cost model.

[43] The EPRI cost spreadsheet assumes that the combined cooling tower pump and fan parasitic load = the cooling tower flowrate in gpm × 0.0000237. See 2011 TDD, Exhibit 8-6, p. 8-18. EPA provide the projected MW capacity for nuclear, fossil fuel, and combined cycle plants with a closed-cycle cooling flowrate of 243,000 pgm in Table 5-12, *Wet Tower Fan Power Energy Penalty*. These MW capcities are: nuclear – 420 MW, fossil – 525 MW, combined cycle – 1,574 MW. If the plant capacities are normalized to 525 MW, the cooling water flowrates become: nuclear – (525 MW/420 MW) × 243,000 gpm = 304,000 gpm; fossil – (525 MW/525 MW) × 243,000 gpm = 304,000 gpm; combined cycle – (525 MW/1,574 MW) × 243,000 gpm = 81,000 gpm

[44] EPA model cooling tower costs are based on a cooling tower with a 10 ^oF approach temperature. EPA identifies representative fan power energy penalties in Table 5-12 of the 2002 TDD for four sample plants. The fan power energy penalties shown are for Plant #3 using a cooling tower with an approach temperature of 10 ^oF and with a flowrate of 243,000 gpm. None of the other cooling towers in Table 5-12 have an approach temperature of 10 ^oF. Table 5-15 of the 2002 TDD, *Summary of Fan and Pumping Energy Requirements as a Percent of Power Output*, incorrectly uses the fan power energy penalty for a 5 ^oF approach cooling tower and not the design 10 ^oF approach cooling tower assumed in the EPA cost model.

penalty estimates from its retrofit cooling tower cost model and not rely on the EPRI cost spreadsheet.

III. Reasonableness of EPA's estimate of retrofit downtime

A. EPA's reasoning on downtime is contradicted by the record

EPA identifies the hook-up time for the Jefferies coal-plant cooling tower retrofit at one week and the Canadys retrofit as four weeks in the 2002 TDD. In other cases, Pittsburg 7 and Palisades Nuclear the specific amount of time necessary to interconnect the retrofit cooling tower was not reported. The Plant Yates (Georgia) retrofit was completed in 2002. The hook-up was carried-out when the plant was off-line for an extended outage at a time the plant was not necessary for grid reliability. Where accurate information is available on hook-up times, specifically at the Canadys Station and Jefferies Station sites, the closed-cycle system hook-up was completed within the scheduled plant outage period. The site-specific retrofit issues at each of these five retrofit sites is summarized in Table 7.

Table 7. Site Specific Issues Associated with Utility Boiler Closed-Cycle Retrofits[45,46]

Site	Issues
Pittsburg Unit 7	Cooling towers replaced spray canal system. Towers constructed on narrow strip of land between canals, no modifications to condenser. Hookup time not reported.
Yates Units 1-5	Back-to-back 2×20 cell cooling tower. 1,050 feet long, 92 feet wide, 60 feet tall. Design approach is 6° F. Cooling tower return pipes discharge into existing intake tunnels. Circulating pumps replaced with units capable of overcoming head loss in cooling tower. Condenser water boxes reinforced to withstand higher system hydraulic pressure. Existing discharge tunnels blocked. New concrete pipes connect to discharge tunnels and transport warm water to cooling tower.
Canadys Station	Distance from condensers to towers ranges from 650 to 1,700 feet. No modifications to condensers. Hookup completed in 4 weeks.
Jefferies Station	Distance from condensers to wet towers is 1,700 feet. No modifications to condensers. Two small booster pumps added. Hookup completed in 1 week.
Palisades Nuclear	The conversion required new circulating pumps due to increased pumping head. No modifications to the condensers were initially carried-out. The condenser tubes subsequently replaced due to leaks unrelated to conversion. The condenser tubes were failing with the once-through system due to vibration. The plant was shut down because of various operational problems in August 1973. Consumers Energy stated that operational problems unrelated to the cooling tower conversion had been mostly responsible for the extended (10 month) outage (see DCN 4-2502).

The EPA established a strong case for one month as a reasonable and conservative outage period for a cooling tower hook-up in the 2002 TDD, stating:

[45] 2002 TDD, Chapter 4.
[46] EPA Region 1, memorandums on conversion of Yates Plant Units 1-5 to closed-cycle cooling, January and February 2003.

2002 TDD, p. 4-6: Based on the information provided to the Agency (including the late Palisades submission), the estimate of one-month could in some cases over- and others under-estimate the expected outage duration for a cooling system conversion.

2002 TDD, p. 4-6, p. 4-7: The Agency also consulted a detailed historical proposal for a Roseton Generating Station cooling system conversion (Central Hudson Gas & Electric, 1977). The report estimates a gross outage period of one-month for the final pipe connections for the recirculating system. The report estimates the net outage as 10 days for one of the two units and no downtime for the second. The reason given for the short estimates of downtime is the coincidence of the connection process with planned winter maintenance outages. Unlike the projection in the 1999 DEIS described above, this 1977 projection was accompanied by a relatively detailed description of the expected level of effort and engineering expectations for connecting the reciruclating system to existing equipment.

2002 TDD, p. 4-9: "The Agency located a reference for a project where four condenser waterboxes and tube bundles were removed and replaced at a large nuclear plant (Arkansas Nuclear One). The full project lasted approximately 2 days. The facility, based on experience, had estimated the full condenser replacement to occur over the course of 8 days. Even though the scope of condenser replacements differ from potential cooling system conversions, the regulatory options considered for flow reduction commensurate with wet cooling anticipate that a subset of conversions would precipitate condenser tube replacements. As such, the condenser replacement schedule is important to the consideration of select cooling system conversions."

2002 TDD, p. 2-19: "The Agency estimates for the flow-reduction regulatory options considered that the typical process of adjoining the recirculating system to the existing condenser unit and the refurbishment of the existing condenser (when necessary) would last approximately two months. Because the Agency analyzed flexible compliance dates (extended over a five-year compliance period), the Agency estimated that plants under the flow reduction regulatory options could plan the cooling system conversion to coincide with periodic scheduled outages, as was the case for the example cases. For the case of nuclear units, these outages can coincide with periodic inspections (ISIs) and refueling. For the case of fossil-fuel and combined-cycle units, the conversion can be planned to coincide with periodic maintenance. Even though ISIs for nuclear units last typically 2 to 4 months, which would extend equal to or beyond the time required to connect the converted system, the Agency estimates for all model plants one month of interrupted service due to the cooling system conversion."

EPA modifies its treatment of construction downtime for nuclear plants in the 2011 TDD, stating that:[47] "In the Phase II NODA, EPA assumed net construction downtimes of 4 weeks for non--nuclear plants and 7 months for nuclear plants. . . Thus, the net value includes a deduction of the estimated maintenance downtime period (4 weeks for non-nuclear facilities) from the total estimated downtime." EPA notes in the Phase II NODA (p. 13525) that "Just prior to proposal, EPA received additional technical information on the amount of operational downtime needed

[47] March 2011 TDD, p. 8-26.

during cooling system conversions from once through to closed-cycle, recirculating with cooling towers at nuclear power plants (*see* DCN 4–2529).”

The reasoning behind these revised EPA construction downtime estimates is provided in the 2003 Phase II NODA:[48]

> *Net Installation Downtime and Other Site-Specific Factors for Recirculating Cooling Towers*
> To support the proposed Phase II rule, EPA assumed that each projected cooling system conversion would require a net downtime of four weeks.
>
> This estimate was based on information that had been previously available to EPA on the downtime needed for fossil fuel and nuclear power plants. Just prior to proposal, EPA received additional technical information on the amount of operational downtime needed during cooling system conversions from once through to closed-cycle, recirculating with cooling towers at nuclear power plants (*see* DCN 4–2529). For the new analyses, EPA is incorporating the new information which suggests that cooling system conversions at nuclear power plants may take seven months. To the extent that conversions at nuclear power plants take less time to complete, costs for this factor would be lower.
>
> For non-nuclear power plants, EPA’s cost estimates at proposal assumed four weeks downtime for the retrofit of wet cooling towers at existing power plants. The Agency requests comment on whether more or less downtime may be required at some plants due to site specific factors and, if so, whether EPA should use a different estimate of downtime in analyzing the costs of this regulatory option.

Nothing new is introduced into the record by EPA between the 2002 TDD and the 2011 TDD that would support extending the construction downtime estimate for nuclear plants from 2 months to 7 months. Comments by the Atomic Energy Commission in the case of Palisades Nuclear and Consolidated Edison in the case of Indian Point Nuclear make clear there are no special safety considerations at nuclear plants for cooling tower retrofits. Therefore there is no basis for EPA to arbitrarily add 5 additional months of outage time for a nuclear plant cooling tower retrofit.

Available information on equipment retrofits at nuclear plants strongly support the position that 2 months is a reasonable and conservative estimate of cooling tower construction downtime at a nuclear plant. EPA points-out in the 2002 TDD that four surface condensers at 846 MW Arkansas Nuclear One were upgraded during two days of downtime. The Arkansas One surface condenser upgrade duration provides insight into just how quickly a large piece of equipment at a nuclear power plant can be modified/upgraded.

The four steam generators at Diablo Canyon Units 1 and 2, 1,150 MW each, were replaced in 2008-2009 with a total outage times of 58 days of 69 days, respectively.[49] The work was done

[48] Phase II NODA, Federal Register /Vol. 68, No. 53 /Wednesday, March 19, 2003 / Proposed Rules FR 13525.
[49] Areva, *Project profile – Diablo Canyon Steam Generator Replacement Projec*t, November 18, 2010. See: http://www.areva-np.com/scripts/us/publigen/content/templates/show.asp?P=1359&L=US.

concurrently with a planned refueling outage.[50] This project required cutting an opening in the nuclear reactor containment dome. Since the containment building and original installation of the steam generators was not intended to provide easy replacement, a completely customized system and innovative assembly process were needed to remove them.

The average duration of a steam generator replacement outage at a nuclear plant is 75 days.[51] A typical refueling outage lasts approximately 40 days.[52] All of the steam generator replacement work takes place within the area of a nuclear plant where safety and security issues are paramount. The steps involved in a steam generator replacement include:[53]

Step 1 All nuclear fuel is removed from the reactor and placed in a building designed for safe storage.
Step 2 A temporary 28-foot by 28-foot opening is created (in the reactor dome) to allow removal of the original steam generators and installation of the new components.
Step 3 The original steam generators are disconnected from their piping and supports.
Step 4 A special crane lifts the original steam generators and places them on a rail system running through the opening, sliding them outside the dome where they are lowered to a heavy haul-vehicle and transported to a storage area.
Step 5 The new steam generators are lifted and placed inside the dome, reversing the process described in Step 4.
Step 6 The new generators are connected to their piping and supports, the crane system removed, the opening resealed, and equipment located where the opening was created reinstalled.
Step 7 Extensive inspections and testing are done to ensure the new components and reactor coolant system are working correctly.
Step 8 Personnel start up the unit and conduct functional testing. Then power production resumes.

It is not credible that the outage time for a highly invasive nuclear reactor steam generator replacement that occurs inside the nuclear containment dome averages 2 to 2-and-a-half months, and yet the hook-up of circulating water piping to an existing nuclear reactor surface condenser, an action the NRC predecessor agency stated would create no nuclear safety concerns, would require a 7-month outage.

EPA's defense of the 7-month outage for nuclear plants in the 2011 TDD is no more than an unsupported opinion that presumes that the need for a 7-month outage is a given. EPA states:[54]

[50] Power Engineering, *Project-of-the-year award winners*, January 2009. See: http://pepei.pennnet.com/articles/print_toc.cfm?Section=ARTCL&p=6
[51] Power Engineering, *How Low Can They Go?*, August 2008, Vol. 112, Issue 8, p. 44. See: http://www.pennenergy.com/index/power/display/337581/articles/power-engineering/volume-112/issue-8/features/how-low-can-they-go.html.
[52] Ibid.
[53] Southern California Edison fact sheet, *Ensuring San Onofre Plant Benefits Continue Through Its Current License*, December 2010.
[54] March 2011 TDD, p. 8-26.

> Riverkeeper (DCN 6-5049A, Comment ID 316bEFR.332.001) argued that the 7-month period for nuclear plants was too long and that the extended duration for the Palisades plant included additional activities not associated with the cooling tower retrofit. EPA responded to Riverkeeper's comments by suggesting that the 7-month period might be on the low side because it is based on historical refueling duration of 2 to 3 months, which has recently dropped to 30 to 40 days. These offsetting arguments support a decision to retain the 7-month net downtime for nuclear power plants.

A two-month outage duration estimate for the hook-up of circulating cooling water piping to an existing surface condenser at a nuclear plant is conservative. EPA should assume no more than a two-month outage duration for a cooling tower hook-up on a nuclear reactor.

IV. The total national pre-tax compliance costs of Option 2 and Option 3 are approximately double a more realistic estimate

EPA estimates that total annualized national pre-tax compliance costs for power plants under Option 2 and Option 3 would be $4,933 million and $5,079 million.[55] The Option 2 and Option 3 estimates are high by 60 to 70 percent. More realistic annualized national compliance pre-tax compliance costs are $3,029 million and $3,104 million, respectively, as shown in Table 8.

Powers Engineering calculated the pre-tax compliance costs of Option 2 and Option 3 based on: 1) EPA's retrofit cost estimate for an wet inline redwood cooling tower adjusted to 2009, 2) the cooling tower capital cost assuming SPX wet tower or ClearSky™ plume-abated tower technology in a back-to-back configuration, and 3) cooling tower energy penalty estimates from the 2002 TDD. No cost was attributed to outage time for a cooling tower hook-up at either a steam boiler plant or a nuclear plant. The Powers Engineering Option 3 pre-tax compliance costs for: 1) initial permit application, 2) O&M, 3) monitoring, recordkeeping, and reporting (MRR), and 4) permit renewal are the same as those in the EPA estimate.

To determine a revised Option 3 capital cost using the alternative Powers Engineering cooling tower capital costs presented in this comment letter, the alternative unit composite cooling tower cost of $222/gpm is divided by the unit capital cost of $293/gpm adopted by the EPA in the March 2011 TDD and then multiplied by the annualized Option 3 nationwide capital cost estimate of $2.788 billion per year. This results in an alternative Option 3 annualized capital cost of: ($222/gpm ÷ $293/gpm) × $2.788 billion/yr) = $2.112 billion per year.

The Powers Engineering Option 2 pre-tax compliance costs are the Powers Engineering Option 3 pre-tax compliance costs pro-rated for the difference in cost between the EPA Option 2 and Option 3 categories. The capital cost in EPA Option 2 is 98 percent of the capital cost in EPA Option 3. This 98 percent factor is applied to the Powers Engineering Option 3 capital cost to calculate the Powers Engineering Option 2 capital cost. The EPA Option 2 pre-tax compliance costs are left unchanged for: 1) initial permit application, 2) O&M, 3) monitoring, recordkeeping, and reporting (MRR), and 4) permit renewal. The energy penalty cost in EPA Option 2 is 95 percent of the energy penalty cost in EPA Option 3. This 95 percent factor is

[55] 2011 EBA, Table 3-7, p. 3-23 and p. 3-24,

applied to the Powers Engineering Option 3 energy penalty cost to calculate the Powers Engineering Option 2 energy penalty cost.

Table 8. Comparison of Annualized Pre-Tax Compliance Costs for Options 2 and 3 ($2009, millions)

Scenario	Capital Cost ($)	Outage	Initial Permit	O&M	MRR	Energy penalty	Permit renewal	Total
Option 2 EPA	2,737	280	1	316	7	1,590	1	4,933
Option 2 Powers	2,070	0.0	1	316	7	634	1	3,029
Option 3 EPA	2,788	296	1	319	4	1,670	1	5,079
Option 3 Powers	2,112	0.0	1	319	4	667	1	3,104

The calculations supporting the Powers Engineering annualized cost estimates for capital cost and energy penalty are provided in **Attachment E**. Both EPA and Powers Engineering use of design intake flow (DIF) for affected facilities to calculate the capital cost of cooling tower retrofits under Options 2 and 3.

However, the calculation of Option 2 and Option 3 compliance costs using the current total U.S. DIF is a very conservative assumption (i.e., actual costs are likely to be lower) given the ongoing coal plant retirement trends unrelated to projected 316(b) compliance costs. That is because, given the trend, the actual number of existing plants needing to be retrofit will likely be smaller.

V. Reasonableness of EPA's position on air pollution issues, including increased emissions due to energy penalty or retrofit downtime as well as particulate emissions from cooling towers

EPA does not consider the full implementation of most recent air emission requirements in opining on the air quality impact of cooling tower retrofits.[56] Instead, the agency uses air emissions data that is on average ten years old at a time when the more recent air emission requirements are rapidly driving down air emissions from existing coal plants.[57] This is a major deficiency in the air quality impacts analysis.

EPA clearly states how overstated its air emissions increase projections are in the 2011 TDD:[58] "For example, the 2010 Air Transport Rule and other state and EPA actions would reduce remaining power plant SO_2 emissions by 71 percent and NO_x emissions by 52 percent. The

[56] 2011 TDD, p. 10-1: "Note that the current emissions rate calculations discussed below do not reflect full implementation of the most recent air rule requirements."
[57] 2011 TDD, p. 10-2: "The data source for the Agency's air emissions estimates of CO_2, SO_2, NO_x, and Hg is the EPA-developed database titled E-GRID 2005. This database is a compendium of reported air emissions, plant characteristics, and industry profiles for the entire US electricity generation industry in the years 1996 through 2005."
[58] Ibid, p. 10-5 and 10-6.

mercury rule would require utilities to install controls to reduce mercury emissions by 29 percent. Since the actual emissions data used in EPA's analysis does not reflect full implementation of these air rules, and since in many cases technologies to reduce emissions have yet to be installed, both the baseline and any potential increase in emissions are overstated."

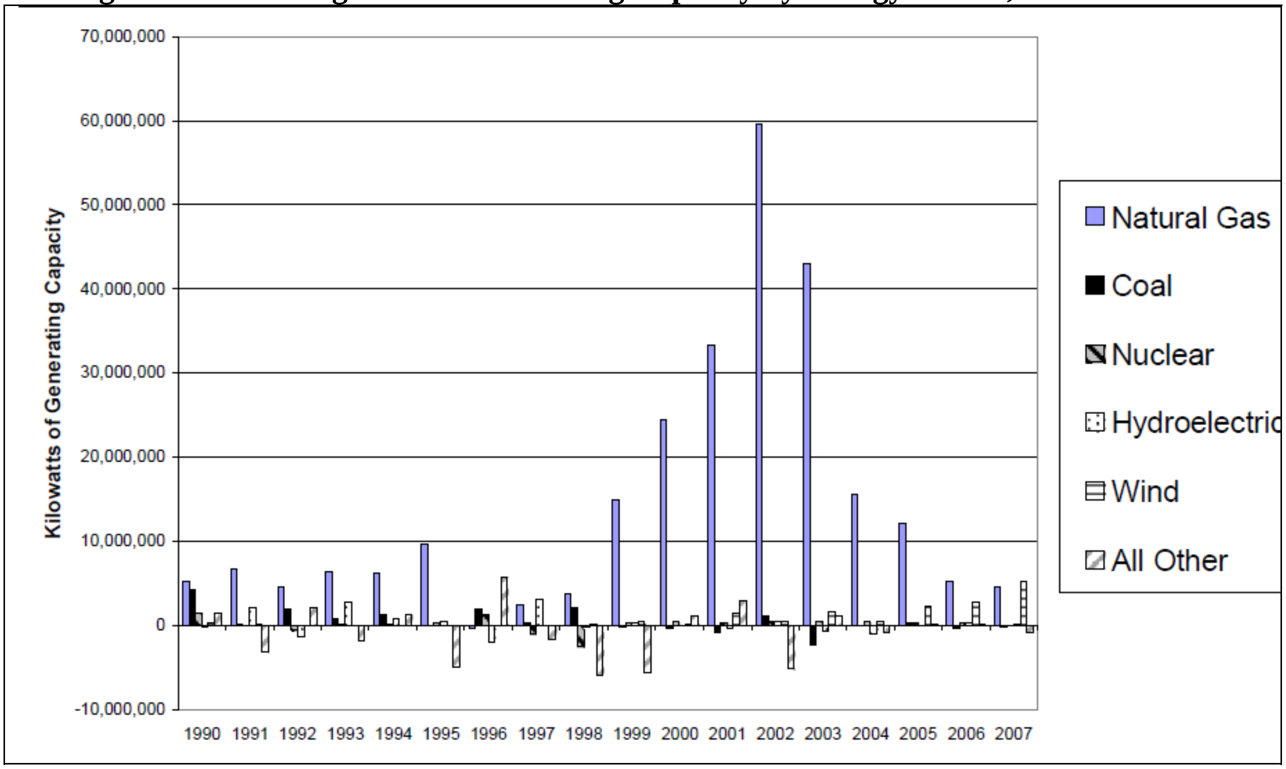
Given the large reductions in NO_x, SO_2, and mercury that will be achieved with implementation of the Cross-State Air Pollution Rule (finalized in July 2011) and the Hazardous Air Pollutants Rule (to be finalized in November 2011), it is not credible for EPA to then state: "Despite these conservative estimates, EPA concludes there is the potential for an increase in total emissions." As discussed above in Section II, the retrofitting of cooling towers at a limited number of U.S. power plants will reduce output from these plants on the order of 1 to 2 percent. Even if all of this output is made up by coal plants, which it will not be as discussed below, the increased output is a small fraction of the percentage reduction of NO_x, SO_2, and mercury that will occur within this same universe of coal plants due to EPA requirements. Air emissions from U.S. coal plants will not increase as a result of cooling tower retrofits at coal and nuclear plants. Air emissions from U.S. coal plants may decrease slightly less dramatically as a result of the retrofits.

Carbon dioxide (CO_2) emissions are currently decreasing in the U.S. power sector, due in part to the shifting of electricity production from coal plants to natural gas-fired plants for economic reasons. The EPA reports a 6.1 percent reduction in CO_2 emissions between 2008 and 2009.[59] A primary reason for this reduction is fuel switching between coal and natural gas. Again, assuming EPA's worst case air emission scenario where coal plants burn more coal to make up for output reductions caused by cooling tower retrofits, so long as fuel shifting from coal to natural gas continues to increase, CO_2 emissions from U.S. electricity generation would decrease slightly less dramatically – not increase.

The reality of the U.S. electricity market is that over 200,000 MW of new, cleaner, and more efficient natural gas fired capacity has entered the market over the last decade, and there is now more natural gas-fired capacity than coal capacity in the country. See Figures 3 and 4. The market trend is moving from coal firing to natural gas firing for economic reasons. One ancillary benefit of this move is the much lower air emissions from modern natural gas-fired capacity.

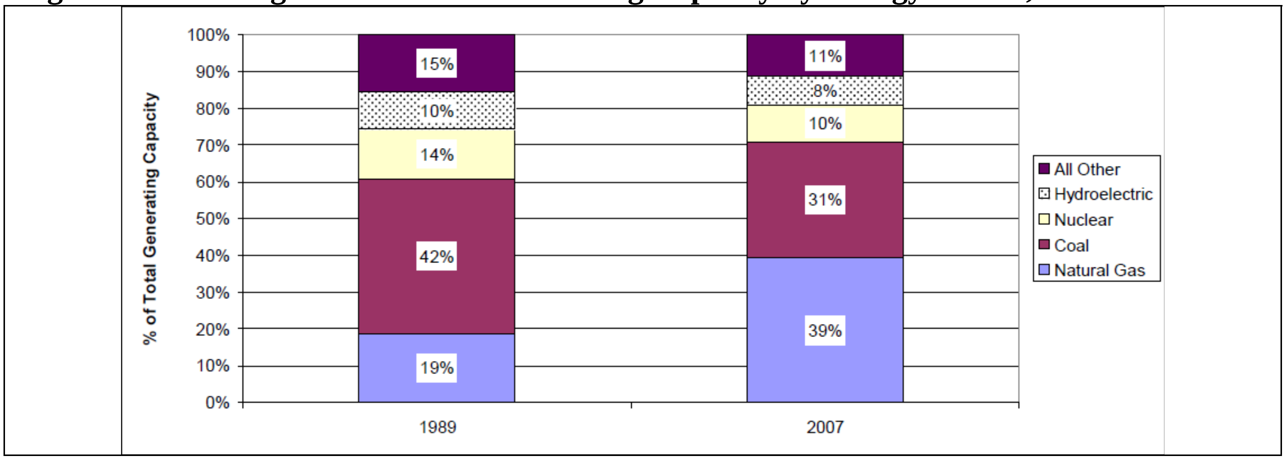
[59] EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks; 1990 – 2009*, April 15, 2011, p. ES-3. "In 2009, total U.S. greenhouse gas emissions were 6,633.2 Tg or million metric tons CO_2 Eq. While total U.S. emissions have increased by 7.3 percent from 1990 to 2009, emissions decreased from 2008 to 2009 by 6.1 percent (427.9 Tg CO_2 Eq.). This decrease was primarily due to (1) a decrease in economic output resulting in a decrease in energy consumption across all sectors; and (2) a decrease in the carbon intensity of fuels used to generate electricity due to fuel switching as the price of coal increased, and the price of natural gas decreased significantly."

Figure 3. Net Change in U.S. Generating Capacity by Energy Source, 1990 to 2007[60]



[60] Congressional Research Service, *Displacing Coal with Generation from Existing Natural Gas-Fired Power Plants*, January 2010, p. 3.

Figure 4. Percentage of Total U.S. Generating Capacity by Energy Source, 1989 - 2007[61]



It is reasonable for EPA to assume that natural gas-fired resources would provide replacement power during peak demand hours, as the primary function of these plants is daytime load-following and peaking power. Air emissions from modern natural gas-fired plants are substantially lower than those of coal-fired plants. By way of example, assume that gas-fired power substitutes for the output reduction at a 2,000 MW nuclear plant caused by a cooling tower retrofit. Output would be reduced about 1.5 percent on an annual average, or 30 MW. If this 30 MW is generated by a load following natural gas fired combined-cycle plant, the annual NO_x and PM_{10} emissions from this output would be about 9 tons/year (0.05 tons/day) and 5 tons/year (0.03 tons/day), respectively.[62,63,64]

The air emissions effect of shifting electricity production from natural gas-fired OTC steam boilers to higher efficiency natural gas-fired combined cycle units is shown in Table 9.[65] All air

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[61] Ibid, p. 4.

[62] CARB, *Guidance for the Permitting of Electric Generation Technologies*, Stationary Source Division, July 2002, p. 9 (NO_x emission factor = 0.07 lb/M-hr combined-cycle plants)

[63] San Diego County Air Pollution Control District (APCD), Otay Mesa Power Project (air-cooled), Authority To Construct 973881, 18 lb/hr particulate without duct firing (510 MW output), equals ~ 0.04 lb/MW-hr.

[64] San Onofre is located in San Diego County. The NO_x and PM_{10} emissions offset thresholds defined by San Diego County APCD Rule 20.1 ("New Source Review General Provisions") are 50 tons/year for NO_x and 100 tpy for PM_{10}. Diablo Canyon is located in San Luis Obispo County. The NO_x and PM_{10} emissions offset thresholds defined by San Luis Obispo APCD Rule 204 ("Requirements") are 25 tons/year for NO_x and 25 tpy for PM_{10}.

[65] California State Water Resources Control Board (SWRCB), *Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling - Final Substitute Environmental Document*, May 2010, Figure 18, p. 109. This report assumes a 5 percent annual average efficiency penalty for cooling tower conversions at the state's two nuclear plants, based on the February 2008 TetraTech report on cooling tower conversions at the state's OTC plants prepared for the SWRCB: http://www.opc.ca.gov/2009/05/california%e2%80%99s-coastal-power-plants-alternative-cooling-system-analysis/. This report assumes average annual turbine efficiency penalties at the two nuclear plants of 2.9 and 3.6 percent, nearly an order of magnitude higher than the average turbine efficiency penalty assumed by EPA for nuclear plants in the 2001 Phase I TDD and 2002 TDD of 0.40 percent. TetraTech includes the EPA Phase I TDD as a reference, but does not acknowledge or address the large difference between its assumed average nuclear turbine efficiency penalty and the value identified by the EPA. TetraTech does not include sufficient reference information to allow independent corroboration of its turbine efficiency penalty calculations. If the EPA's average nuclear plant total energy penalty (turbine efficiency + fan power + pump power) of 1.5 percent is assumed, the PM_{10} increase shown in Table 7 would drop by more than half.

emissions decline, with the exception of particulate emissions from cooling tower drift. This air emissions reduction effect would be much more pronounced in the case of production shifting for coal-fired OTC units to combined cycle units.

Table 9. Air Emissions Effect of Shifting Generation from Natural Gas-Fired OTC Boilers to Natural Gas-Fired Combined Cycle Units[66]

	Fuel Usage (MMBTU)	SO_2 (tons)	NO_2 (tons)	CO_2 (tons)	CO (tons)	TOG (tons)	ROG (tons)	PM10 (tons)
Baseline	151,648,525	53	557	9,070,258	3,116	413	116	262
Repowered Fossil [a]	118,351,861	43	402	7,030,961	2,104	280	104	267
Retrofitted Nuclear	12,760,349 [b]	5	63	757,965	321	28	9	20
Net Change	**-14%**	**-9%**	**-17%**	**-14%**	**-22%**	**-26%**	**-3%**	**10%**

Notes:
a. Based on average emission factors for new, dry-cooled combined-cycle units.
b. Fuel usage for retrofitted nuclear facilities refers to the additional fuel that would have to be consumed by a combined-cycle fossil unit to replace the generating shortfall from the nuclear facilities.

Most nuclear plants in the country have uprated their output capacity significantly in the last 10 to 15 years. These nuclear uprates have added capacity equivalent to five new nuclear plants.[67] Additional uprates are expected to add the equivalent of three-and-a-half more reactors over the next four years.[68] These uprates mean that U.S. reactors, in most cases, will be producing significantly more power than the original design rating even after these units are converted to cooling towers.[69] Collectively, as a result of the uprates, the nuclear fleet will produce more power compared to original capacity ratings even if all OTC nuclear units are retrofitted to cooling towers.

The amount of electricity generated from coal declined 11.6 percent in the 2008-2009 timeframe, primarily due to fuel switching between coal and existing combined cycle plants for economic reasons.[70] The coal to combined cycle fuel switching is expected to continue for at least the next decade based on current natural gas price forecasts. The air emissions decline associated with an 11.6 percent reduction in electricity generation from coal is an order of magnitude greater than the potential air emissions associated with a total energy penalty of 1.24 percent for the subset of coal plants that undergo a cooling tower retrofit.

Also, many parts of the country now have renewable portfolio standards and are actively adding solar and other forms of renewable energy capacity. Non-polluting forms of energy will also

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[66] Ibid, Table 25, p. 110.
[67] Los Angeles Times, *U.S. is increasing nuclear power through uprating*, April 17, 2011. "But uprates have played an important role, adding the equivalent output of nearly five average-sized reactors since 1996. Regulators say they expect to approve boosts totaling 3 1/2 more reactors over the next four years."
[68] Ibid.
[69] Los Angeles Times, *Uprates at U.S. nuclear power reactors*, April 20, 2011. Virtually all uprates are 1.4 percent or greater. The EPA retrofit cooling tower cost model estimates a total energy penalty of about 1.5 percent for a cooling tower with a 10 ^{o}F approach temperature: turbine efficiency penalty, 0.40 percent; fan power energy penalty, 0.56 percent; pump power energy penalty, 0.55 percent. Total energy penalty: 0.40 percent + 0.56 percent + 0.55 percent = 1.51 percent.
[70] Energy Information Administration, *Electric Power Annual 2009*, April 2011, pp, 1-2.

partially or fully displace the reduced output from cooling tower retrofits. This is illustrated in Figure 3 (new generation additions), which shows that wind power additions were second to natural gas-fired additions in 2005, 2006, and 2007.

EPA erroneously infers that fine particulate emissions ($PM_{2.5}$) from cooling tower drift could create difficulty in obtaining necessary air permits in $PM_{2.5}$ non-attainment areas.[71] This inference is based in part on the overly conservative assumption that all particulate emitted by a cooling tower is PM_{10}. PM_{10} emissions are a fraction of total particulate emissions from cooling towers, and the $PM_{2.5}$ component is small subset of the PM_{10} fraction.[72]

In some non-attainment jurisdictions, cooling towers are exempt from air permit requirements.[73,74] In those areas where they may not be exempt and where: 1) a plant is located in a $PM_{2.5}$ non-attainment area, 2) cooling tower $PM_{2.5}$ emissions are subject to an air permit requirement, and 3) projected cooling tower $PM_{2.5}$ emission levels may be deemed to trigger major $PM_{2.5}$ source status, then the plant owner could be required to purchase or generate sufficient $PM_{2.5}$ emission offsets to prevent a net increase in $PM_{2.5}$ emissions. In such an event, the requirement to purchase or generate $PM_{2.5}$ emission offsets could increase the cost of securing an air permit for the cooling tower. The implication by EPA that cooling towers would be banned in some jurisdictions because they would or could emit PM_{10} or $PM_{2.5}$ above certain thresholds is wrong.

VI. EPA's determination that many existing plants lack space for cooling towers is incorrect due to the agency's failure to consider back-to-back cooling towers

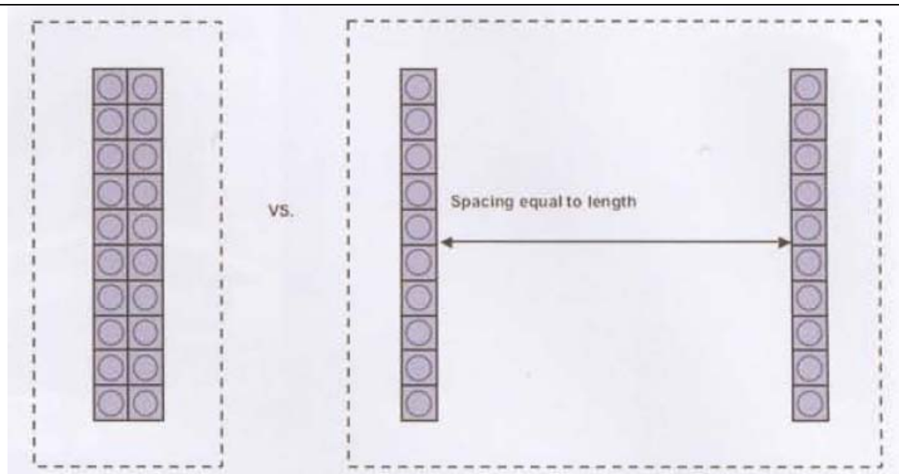
EPA is considering a determination that any plant with more than 160 acres per 1,000 MW of generating capacity would be presumed to have enough space for cooling towers, but that plants below may lack sufficient space.[75] However, this proposed rule-of-thumb is based on the use of

[71] 2011 TDD, p. 6-11: "For example, EPA's analysis suggests that increased emissions of $PM_{2.5}$ may result in difficulty in obtaining air permits in those localities designated as non-attainment areas. For PM_{10}, see DCN 10-6954, which states that emissions would be approximately 60 tons per year if all drift is PM_{10}."
[72] J. Reisman, G. Frisbie, *Calculating Realistic PM_{10} Emissions from Cooling Towers*, Electric Utility Environmental Conference, January 2003, p. 4. "More than 85% of the mass of the particulate in the drift from most cooling towers will result in solid particles greater than PM_{10} once the water has evaporated." This statement is made based on analysis of drift from an expamle cooling tower with 7,700 ppm total dissolved solids in the cooling tower circulating water and a drift eliminator efficiency of 0.0006%. This paper is often cited by new fossil plant applicants as the basis for air permit application cooling tower PM_{10} and $PM_{2.5}$ emission estimates.
[73] SCAQMD Rule 219, Equipment Not Requiring a Written Permit, (d)(3) – water cooling towers. See: http://www.aqmd.gov/rules/siprules/sr219.pdf.
[74] San Diego APCD Rule 11, Exemptions from Rule 10 Permit Requirements, (6)(vii) – water cooling towers. See: http://www.sdapcd.org/rules/Reg2pdf/R11.pdf.
[75] 2011 TDD, p. 5-24: "While EPA believes that the vast majority of facilities have adequate available land for placement of cooling towers, some facilities may have legitimate feasibility constraints. Based on site visits, EPA has found several facilities have been able to engineer solutions when faced with limited available land. EPA attempted to determine a threshold of land (one option explored a threshold of approximately 160 acres per gigawatt) below which a facility could not feasibly install cooling towers. Based on such an approach, EPA projected an upper bound of 25 percent of facilities that may have insufficient space to retrofit to cooling towers. While EPA estimated that some facilities would not have enough space, EPA found some facilities with a small parcel of land were still able to install closed-cycle cooling by engineering creative solutions."

land-intensive in-line cooling towers, not much more space efficient back-to-back cooling towers.[76]

Figure 5 shows a comparison of site requirements for two in-line towers compared to one back-to-back tower that provides the same cooling capacity. The back-to-back cooling tower requires about 17 percent of the space needed for two in-line towers, assuming the spacing recommended for parallel banks of in-line towers. The recommended in-line tower spacing is for the distance between the towers to equal the length of the towers, as shown in Figure 5.

Figure 5. Comparison of Siting Requirements – Back-to-Back Versus In-Line Cooling Towers[77]



EPA should not attempt to set any "acreage-to-MW" rule-of-thumb that would presumptively exempt large numbers of plants from installing retrofit cooling towers. EPA did not consider the one cooling tower technology specifically intended for constrained sites – back-to-back cooling towers – in its analysis of cooling tower space requirements. Back-to-back cooling towers require only 17 percent the space of the in-line cooling towers evaluated by the EPA in its consideration of a "limited space exemption" threshold of approximately 160 acres per 1,000 MW. This threshold would drop to approximately 27 acres per 1,000 MW if the cooling tower configuration assumed is back-to-back.[78]

Back-to-back cooling towers, both wet and plume-abated, are in commercial use in the U.S. Figure 6 provides examples of operational back-to-back cooling towers and a ClearSky™ cell in operation in New Mexico.

[76] Ibid, p. 8-23: "The EPRI worksheet contains numerous assumptions and default values that can be modified using site-specific data. Specific relevant assumptions and default values are listed below . . . Tower configuration was in-line rather than back-to-back, meaning towers are oriented in single rows rather than rows of two towers side by side."
[77] P. Lindahl, K. Mortensen – SPX Cooling Technologies, *Plume Abatement – The Next Generation*, Cooling Technology Institute (CTI) Journal, Volume 31, No. 2, 2010, Figure 20, p. 22.
[78] 0.17 × 160 acres per 1,000 MW = 27 acres per 1,000 MW.

Figure 6. Examples of Operational U.S. Back-to-Back Cooling Towers and ClearSky Cell

Plant Yates, Georgia

Plant Branch, Georgia

Bergen Generating Station, New Jersey

ClearSky cell, New Mexico (far left)

ClearSky™ is the plume-abated cooling tower option preferred by major steam boiler plant operators that may need to carry-out cooling tower retrofits at facilities located in populated areas. An example is the analysis by URS for GenOn of the cooling tower retrofit options for the Ormond Beach Generating Station (OBGS) steam boiler plant in California. Regarding fresh water cooling tower (FWCT) and salt water cooling tower (SWCT) alternatives, GenOn states:[79]

> GenOn engaged URS to consider the physical feasibility of installing FWCTs or SWCTs.
>
> As a threshold matter, due to the visual impacts that would result from a cooling tower plume on the Point Mugu Naval Air Station and on visual resources, especially adjacent beach recreation areas, plume abatement would be required for any FWCT or SWCT installation at the OBGS under the provision of CEQA. Therefore, throughout the rest of this Implementation Plan, the descriptions and analysis of FWCTs and SWCTs assume that they incorporate plume abatement.
>
> There are two potential options for plume abatement technology: the conventional "Hybrid" type tower and the "Clear Sky" type cooling tower. Hybrid towers are significantly larger

[79] GenOn West, L.P., *Ormond Beach Generating Station Implementation Plan for the Statewide Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling*, April 1, 2011, pp. 19-21.

> and may be appropriate for FWCTs. In saltwater applications, however, Hybrid towers would require installation of costly titanium heating coils, which would require frequent, extensive maintenance. For these reasons, only the Clear Sky technology would be practical for a SWCT application, although it could also be used in FWCTs. It is important to note, however, that there has been no full-scale commercial application of a Clear Sky cooling tower to date. While there is a significant technological feasibility question regarding the full-scale commercial application of the Clear Sky product, for the purpose of assessing feasibility at the OBGS, this analysis assumed it would be available and effective commercially.
>
> URS determined that, based on site layout, the configuration of the existing units, and available space at the OBGS site, a Clear Sky plume-abated FWCT could theoretically be constructed at the site. . . . URS determined that, based on site layout, the configuration of the existing units, and available space at the OBGS site, a Clear Sky plume-abated SWCT could theoretically be physically constructed.

Back-to-back cooling towers can be retrofitted onto existing sites with very limited space. One example is shown in Figure 7. A 12-cell ClearSky™ plume-abated back-to-back cooling tower, designed for a 12 °F approach temperature and 20 °F range, would be placed in the employee parking area to provide closed-cycle cooling for 324 MW of base load capacity at this space-constrained urban plant. The space requirement for the 12-cell plume-abated back-to-back cooling tower is about three-quarters of an acre.[80]

[80] In this example, if retention of a full complement of employee parking is necessary, the retrofit can include adding a multi-deck parking structure to regain the desired number of parking spaces.

Figure 7. Possible Location for Back-to-Back Cooling Tower in Employee Parking Area at Urban, Space-Constrained Steam Boiler Plant[81]

There are likely to be few power plants in the country with an acreage-to-capacity ratio, based on use of back-to-back cooling towers, of less than 27 acres per 1,000 MW. No limited acreage exemption should be put forward by the EPA. As the agency notes, "EPA found some facilities with a small parcel of land were still able to install closed-cycle cooling by engineering creative solutions."[82] Creative solutions, like back-to-back cooling towers in parking areas or placed where non-essential structures are currently located, generally address the concern that insufficient land is available to locate cooling towers at acreage-limited power plants.

VII. Uncertainties regarding remaining useful plant life should not be used as an excuse to avoid cooling tower retrofits

The EPA states that "Making major structural and operational changes (such as retrofitting to closed-cycle cooling) may not be an appropriate response for a facility or unit that will not be operating in the near future."[83] This is a reasonable statement to the extent that the plant owner has made a legally binding commitment to permanently retire the once-through cooled units within, for example, a 5-year period. If a plant operator cannot make a legally binding commitment to permanently retire the units within such a timeframe, then the units should get no special consideration from the EPA regarding remaining useful life.

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[81] Bill Powers, P.E., *Declaration on Feasibility and Cost-Effectiveness of Cooling Tower Retrofit at GenOn Potomac River, LLC Potomac River Generating Station (May 2007 Draft NPDES Permit DC 0022004)*, February 18, 2011.
[82] 2011 TDD, p. 5-24.
[83] Ibid, p. 6-11.

VIII. Permit application requirements and compliance timelines

EPA should define the expected retrofit cooling tower cost and O&M values to be used in permit applications to minimize the tendency of each applicant to "reinvent the wheel" to the detriment of actually carrying-out a cooling tower conversion. These default values should reflect the agency's extensive evaluation and verification of these costs and parameters. Recommended default values for permit applications are:

Installed retrofit cost, wet tower (in-line or back-to-back), $/gpm:	182 – 223
Installed retrofit cost, plume-abated tower (in-line or back-to-back), $/gpm:	316 – 411
Average turbine efficiency penalty (fossil or nuclear), %:	0.30 – 0.40
Average fan parasitic energy penalty (fossil or nuclear), %:	0.40 – 0.60
Average pump parasitic energy penalty (fossil or nuclear), %:	0.40 – 0.60
Total retrofit downtime, months:	fossil – 1, nuclear – 2

EPA employees or EPA contractors should be the sole arbiters of the technical adequacy of applications, not peer reviewers hired by the applicant. Peer reviewers hired by the applicant, regardless of whether the EPA has authority to opine on the adequacy of the proposed peer reviewer, will generally be advocates for the applicant's position, whether or not that position is technically sound.

As the EPA notes, most existing OTC plants previously subject to the Phase II rule have already prepared cooling tower conversion studies.[84] For example, preliminary cooling tower retrofit evaluations have been conducted for all California OTC plants, and the document containing these preliminary retrofit evaluations is cited in the 2011 TDD.[85] As a result, the start-to-finish application process for cooling tower conversions for these facilities should be no more than 24 months.

Cooling tower retrofit(s) should be completed no more than 36 months after approval of the application. A 36-month timeline is set in the compliance order for conversion of Dominion Energy's Brayton Point Station to cooling towers.[86] The one exception would be nuclear plants that may need up to 12 additional months to synchronize the cooling tower retrofit outage with the reactor refueling outage. This compliance schedule is based on the expectation that the outage necessary for typical cooling tower hook-ups at fossil plants would be no greater than the

[84] Federal Register /Vol. 76, No. 76 /Wednesday, April 20, 2011 / Proposed Rules, p. 22254.

[85] 2011 TDD, p. 2-12. "In February 2008, California Ocean Protection Council completed a study entitled, California's Coastal Power Plants: Alternative Cooling System Analysis, (DCN 10-6964) which evaluates the feasibility of retrofitting coastal facilities to closed-cycle cooling towers to mitigate impingement and entrainment impacts at these sites. EPA reviewed this study to identify site-specific considerations involved in cooling tower retrofits."

[86] U.S. Environmental Protection Agency Region I - New England, Docket 08-007, In the matter of Dominion Energy Brayton Point, LLC, Brayton Point Power Station, Somerset, Massachusetts, NPDES Permit No. MA0003654Proceedings under Section 309(a)(3) of the Clean Water Act, as amended, *Findings and Order for Compliance*, pp. 5-6. "Within 29 months of obtaining all permits and approvals, commence tie-in of condenser units to cooling towers. . . Within 36 months of obtaining all permits and approvals, complete tie-in of all condensor units such that all permit limits are met."

typical four-week annual maintenance outage, and the typical outage necessary for a cooling tower hook-up at nuclear plants would be no greater than the typical 40-day refueling outage.

There is no technical need or justification for EPA's proposed extended implementation schedule for cooling tower retrofits.[87] The only time it might be critical to avoid having substantial numbers of fossil and nuclear plants offline is during the June – September peak demand period in any year. There should be no grid reliability issues associated with bringing plants offline during the October – May period, when far more electrical generation reserves are available than necessary to serve the demand. This is already industry scheduling practice for maintenance and refueling outages.

EPA states in the 2011 TDD that "nuclear facilities were permitted a longer timeline to account for additional requirements due to NRC licensing and approvals,"[88] but in the same document EPA notes the NRC has identified no safety issues related to cooling tower retrofits at nuclear plants.[89] There is no technical or safety justification for a period of greater than three years between the time a fossil fuel plant is directed to carry-out a cooling tower retrofit and the time that cooling tower is operational. In the case of a nuclear plant, up to one additional year may be justifiable to synchronize the cooling tower outage with the reactor refueling outage.

My resume is included as **Attachment F**. Please contact me at (619) 295-2072 or bpowers@powersengineering.com if you have any questions about the content of this comment letter.

Regards,

Bill Powers, P.E.

Bill Powers, P.E.

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[87] 2011 TDD, p. 7-5: Extended implementation: "EPA evaluated an extended compliance timeline for several options (especially those involving closed-cycle cooling) to mitigate concerns over grid reliability and add flexibility. For example, the Director could schedule facility compliance timelines to avoid multiple baseload facilities from being offline at the same time. In some cases, additional time to comply would allow opportunity for transmission system upgrades to further mitigate local reliability. Further, this would allow installation outages (downtime) to be coordinated with each specific facility's maintenance schedule. Under this option, most existing facilities would have no more than 10 years to complete the retrofit to closed-cycle cooling. The Director would determine when and if any such schedule for compliance is necessary, and if the facility is implementing closed-cycle as soon as possible. This provision would give the Director the discretion to provide nuclear facilities with up to 15 years to complete the retrofit, because all nuclear facilities baseload generating units and the additional flexibility in timelines would further mitigate energy reliability, and because the retrofits at these types of facilities in particular involve additional complexities and safety issues. The 15 years for nuclear facilities also provides an opportunity to schedule the installation outage to coincide with safety inspections, uprates, and other outages due to major facility modifications."

[88] Ibid, p. 7-6.

[89] Ibid, p.6-9.

Nuclear Plant Retrofit Comparison for Powers Engineering 9-June-2009

	Case 1A	Case 2A	Case 1B	Case 2B
Water	Salt	Salt	Fresh	Fresh
Type	ClearSky BTB	Wet BTB	ClearSky BTB	Wet BTB
Cells	3x22=66	3x18=54	3x20=60	3x18=54
Footprint	3@529x109	3@433x109	3@481x109	3@433x109
Rough Budget	$115.6 million	$38.6	$109.1	$36.4

Basis: 830,000 gpm at 108-88-76. Plume point is assumed at 50 DB/90% RH.

Low clog film type fill is used for all of the selections, assuming any fresh water used would likely be reclaimed water of some sort. Low clog fill has been used successfully in various sea water applications. Intake screens would be required for the make-up sea water to limit shells, etc. Make-up for the ClearSky tower would be approximately 80-85% of the wet tower make-up on an annual basis. Budget is tower only, not including basins. Infrastructure cost is estimated by some at 3 times the cost of the wet tower, including such things as site prep, basins, piping, electrical wiring and controls, etc. Sub-surface foundations such as piling can add significantly, and may be necessary for a seacoast location. The estimates above are adjusted for premium hardware and California seismic requirements, which are a factor in the taller back-to-back (BTB) designs both for wet and ClearSky. These are approximate comparisons. Both the wet towers and ClearSky towers could likely be optimized more than what has been estimated here, and may have to be tailored to actual site space in any event. ClearSky has pump head like a wet tower, is piped like a wet tower, and has higher fan power than a wet tower to accommodate the increased air flow and pressure drop.

Coil type wet dry towers would cost significantly more, with premium tube (titanium for sea water, and possibly for reclaimed water) and header materials. An appropriate plenum mixing design has yet to be developed, but would also require non-corrosive materials and high pressure drop on the air side. No coil type BTB wet dry towers are likely to be proposed.

Bill Powers

From: PAUL.LINDAHL@ct.spx.com
Sent: Tuesday, June 09, 2009 9:27 AM
To: bpowers@powersengineering.com
Subject: Nuclear Comparison

Bill,

A comparison of wet and ClearSky back to back towers for a reference duty is included in the attached summary.

SPX

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Attachment B

SPX
COOLING TECHNOLOGIES

COOLING TOWER INFORMATION INDEX

ISSUE: 1
SECTION: Basics

SUBJECT: **COOLING TOWER PERFORMANCE**
Basic Theory and Practice

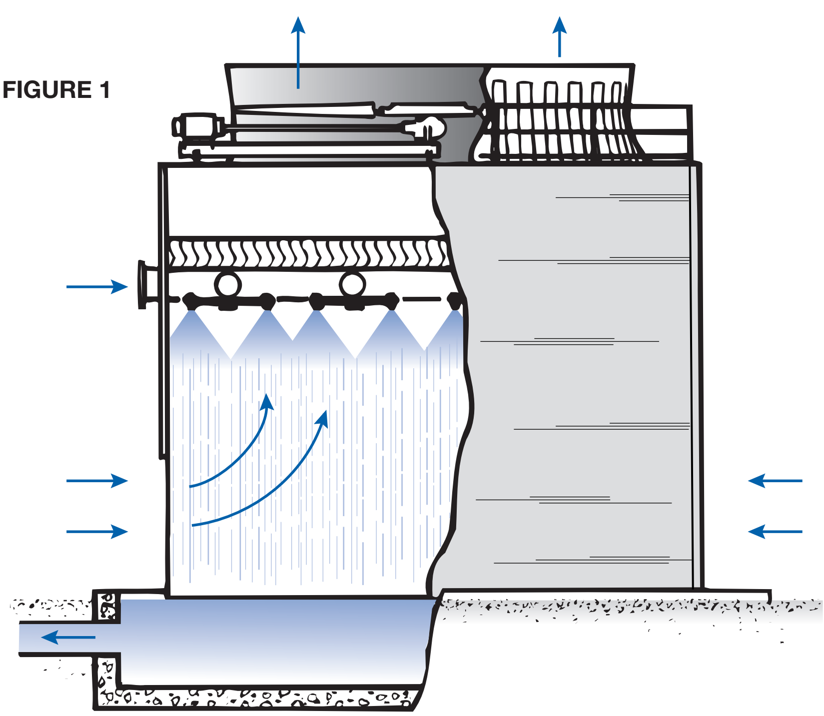
INTENT

In the foreword of *Cooling Tower Fundamentals* (published by SPX Cooling Technologies, Inc.) the scope of cooling tower knowledge was recognized as being too broad to permit complete coverage in a single publication. As a consequence, treatment of the subject matter appearing in that book may have raised more questions than it gave answers. And, such was its intent—"to provide a level of basic knowledge which will facilitate dialogue, and understanding, between user and manufacturer." In short, it was designed to permit questions to spring from a solid foundation—and to give the user a basis for proper evaluation of the answers received.

This is the first of a series of papers intended to expand upon the basic information already published. The plan for the series is to limit individual topics to as few aspects of cooling tower design, application, and operation as necessary to make for quick and informative reading. From time to time, however, subjects will arise whose scope precludes adequate coverage in a short paper, and whose thread of continuity would be lost in separate installments. Those subjects will be treated in "Technical Reports" of somewhat greater length, receiving the same distribution as will have been established by evidence of reader interest. In addition, existing publications whose content remains current and fundamentally sound will become part of the useful cooling tower library that recipients will compile.

Although this first paper touches briefly upon the theory of cooling tower performance, the basic content of future papers will be far more practical than theoretical. This is because the brands of SPX Cooling Technologies, in their course of existence, have designed and manufactured every type of tower currently utilized in the industry, which allows all information and comparisons given to come from experience. However, since the operating characteristics of any cooling tower are governed by the laws of physics, psychrometrics, and thermodynamics, such laws may be described occasionally for purposes of promoting complete understanding.

FIGURE 1



TOTAL HEAT EXCHANGE

An open circuit cooling tower, commonly just called a cooling tower, is a specialized heat exchanger in which two fluids (air and water) are brought into direct contact with each other to affect the transfer of heat. In the "spray-filled" tower shown in **Figure 1**, this is accomplished by spraying a flowing mass of water into a rain-like pattern, through which an upward moving mass flow of cool air is induced by the action of a fan.

Ignoring any negligible amount of sensible heat exchange that may occur through the walls (casing) of the tower, the heat gained by the air must equal the heat lost by the water. Within the air stream, the rate of heat gain is identified by the expression $G\,(h_2 - h_1)$, where:

G = Mass flow of dry air through the tower—lb/min.
h_1 = Enthalpy (total heat content) of entering air—Btu/lb of dry air.
h_2 = Enthalpy of leaving air—Btu/lb of dry air.

Within the water stream, the rate of heat loss would appear to be $L\,(t_1 - t_2)$, where:

L = Mass flow of water entering the tower—lb/min.
t_1 = Hot water temperature entering the tower—°F.
t_2 = Cold water temperature leaving the tower—°F.

This derives from the fact that a Btu (British thermal unit) is the amount of heat gain or loss necessary to change the temperature of 1 pound of water by 1° F.

However, because of the evaporation that takes place within the tower, the mass flow of water leaving the tower is less than that entering it, and a proper heat balance must account for this slight difference. Since the rate of evaporation must equal the rate of change in the humidity ratio (absolute humidity) of the air stream, the rate of

FIGURE 2

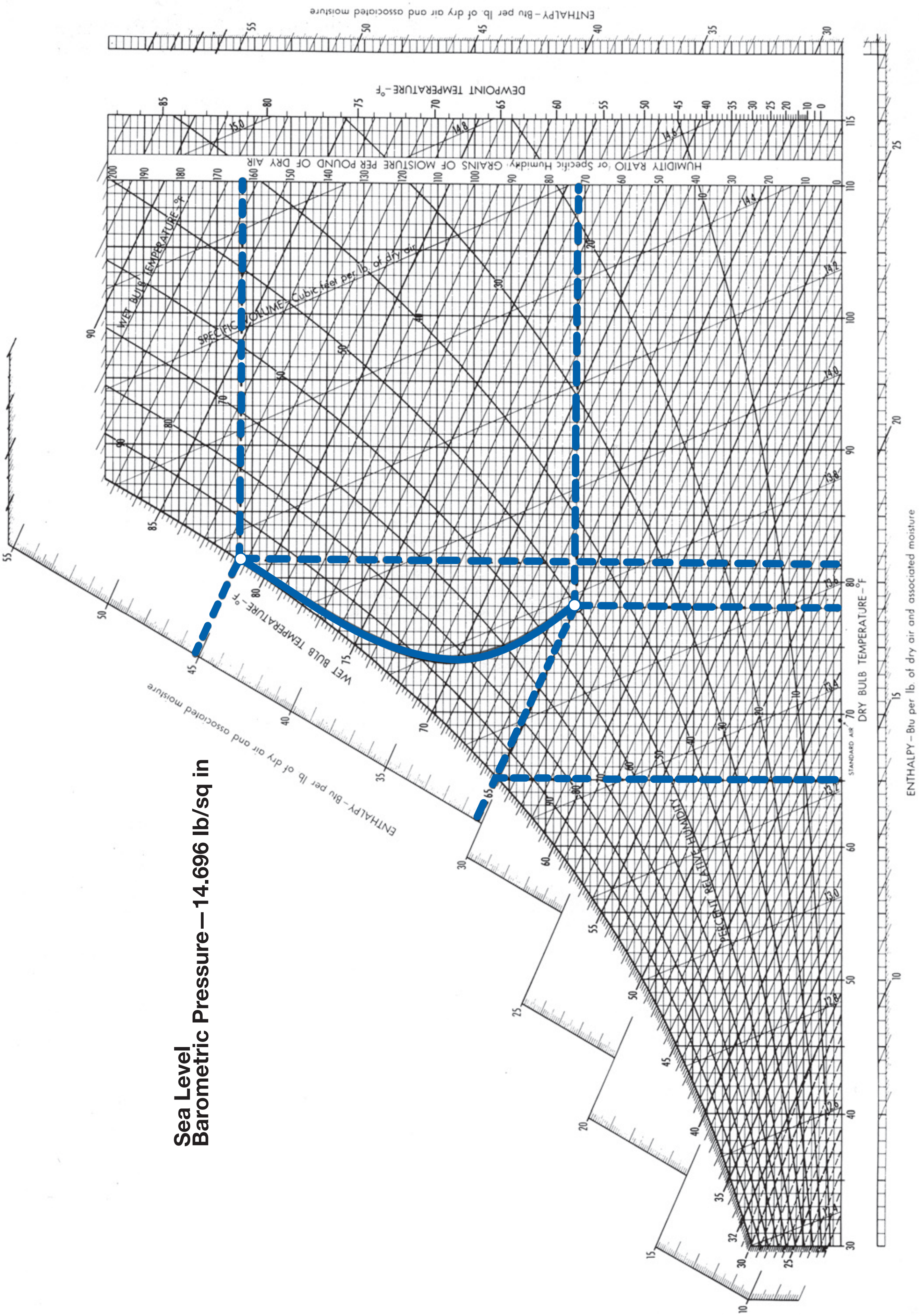
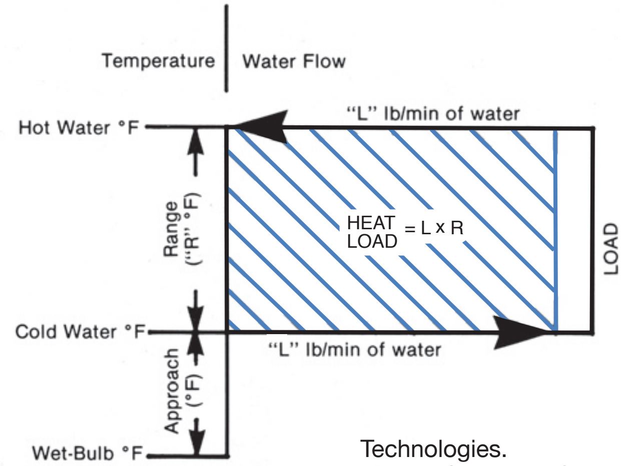

Sea Level
Barometric Pressure—14.696 lb/sq in
ENTHALPY—Btu per lb. of dry air and associated moisture
DEWPOINT TEMPERATURE—°F
HUMIDITY RATIO or Specific Humidity, GRAINS OF MOISTURE PER POUND OF DRY AIR
WET BULB TEMPERATURE—°F
SPECIFIC VOLUME—Cubic feet per lb. of dry air
PERCENT RELATIVE HUMIDITY
DRY BULB TEMPERATURE—°F
STANDARD AIR

FIGURE 3



heat loss represented by this change in humidity ratio can be expressed as G (H_2 - H_1) (t_2 - 32), where:

H_1 = Humidity ratio of entering air—lb vapor/lb dry air.
H_2 = Humidity ratio of leaving air—lb vapor/lb dry air.
(t_2 - 32) = An expression of water enthalpy at the cold water temperature—Btu/lb. (The enthalpy of water is zero at 32°F)

Including this loss of heat through evaporation, the total heat balance between air and water, expressed as a differential equation, is:

$$Gdh = Ldt + GdH (t_2 - 32) \qquad (1)$$

The total derivation of equation (1) can be found in *A Comprehensive Approach to the Analysis of Cooling Tower Performance* by D.R. Baker and H.A. Shryock, printed in the August 1961 issue of the Journal of Heat Transfer, and available from Marley Cooling Technologies.

HEAT LOAD, RANGE & GPM

The expression "Ldt" in equation (1) represents the heat load imposed on the tower by whatever process it is serving. However, because pounds of water per unit time are not easily measured, heat load is usually expressed as:

$$\text{Heat Load} = \text{gpm} \times R \times 8⅓ = \text{Btu/min.} \qquad (2)$$

Where:
gpm = Water flow rate through process and over tower—gal/min.
R = "Range" = Difference between hot and cold water temperatures—°F. (See Fig. 3)
8⅓ = Pounds per gallon of water.

Note from formula (2) that heat load establishes only a required temperature differential in the process water, and is unconcerned with the actual hot and cold water temperatures themselves. Therefore, the mere indication of a heat load is meaningless to the Application Engineer attempting to properly size a cooling tower. More information of a specific nature is required.

Optimum operation of a process usually occurs within a relatively narrow band of flow rates and cold water temperatures, which establishes two of the parameters required to size a cooling tower—namely, gpm and cold water temperature. The heat load developed by the process establishes a third parameter—hot water temperature coming to the tower. For example, let's assume that a process developing a heat load of 125,000 Btu/min performs best if supplied with 1,000 gpm of water at 85°F. With a slight transformation of formula (2), we can determine the water temperature elevation through the process as:

$$R = \frac{125{,}000}{1{,}000 \times 8⅓} = 15°F$$

Therefore, the hot water temperature coming to the tower would be 85°F + 15°F = 100°F.

WET-BULB TEMPERATURE

Having determined that the cooling tower must be able to cool 1,000 gpm of water from 100°F to 85°F, what parameters of the entering air must be known? Equation (1) would identify enthalpy to be of prime concern, but air enthalpy is not something that is routinely measured and recorded at any geographic location. However, wet-bulb and dry-bulb temperatures are values easily measured, and a glance at **Figure 2** (psychrometric chart) shows that lines of constant wet-bulb are parallel to lines of constant enthalpy, whereas lines of constant dry-bulb have no fixed relationship to enthalpy. Therefore, wet-bulb temperature is the air parameter needed to properly size a cooling tower, and its relationship to other parameters is as shown in the **Figure 3** diagram.

FIGURE 4

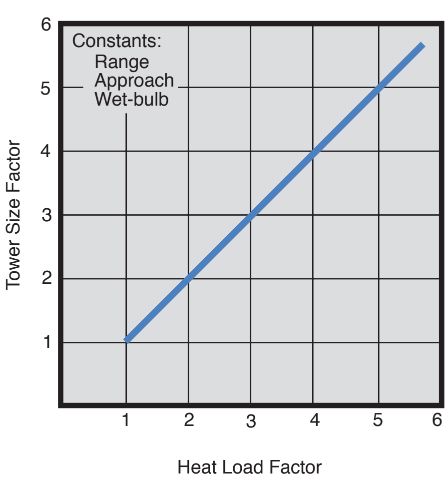
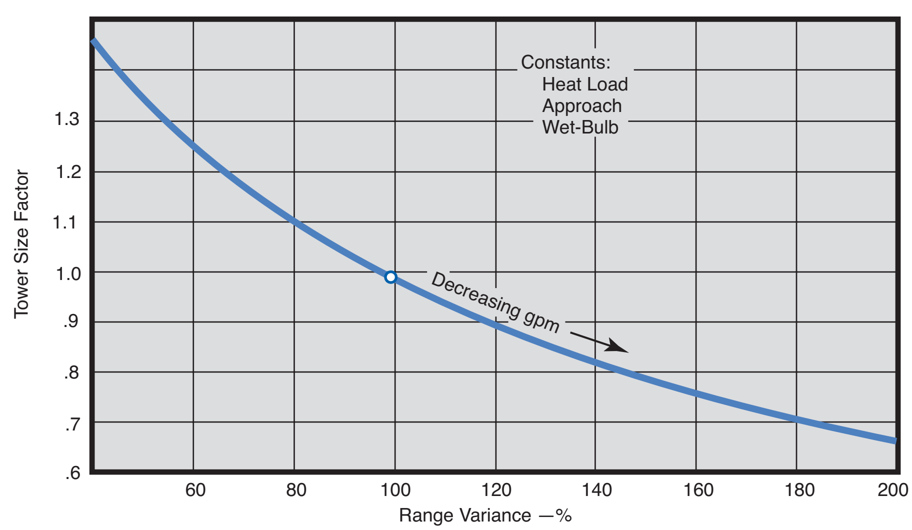


FIGURE 5



EFFECTS OF VARIABLES

Although several parameters are defined in **Figure 3**, each of which will affect the size of a tower, understanding their effect is simplified if one thinks only in terms of 1) heat load; 2) range; 3) approach; and 4) wet-bulb temperature. If three of these parameters are held constant, changing the fourth will affect the tower size as follows:

1) Tower size varies directly and linearly with heat load. See **Figure 4**.
2) Tower size varies inversely with range. See **Figure 5**. Two primary factors account for this. First; increasing the range—**Figure 3**—also increases the ITD (driving force) between the incoming hot water temperature and the entering wet-bulb temperature. Second, increasing the range (at a constant heat load) requires that the water flow rate be decreased—Formula (2)—which reduces the static pressure opposing the flow of air.
3) Tower size varies inversely with approach. A longer approach requires a smaller tower. See **Figure 6**. Conversely, a smaller approach requires an increasingly larger tower and, at 5°F approach, the effect upon tower size begins to become asymptotic. For that reason, it is not customary in the cooling tower industry to guarantee any approach of less than 5°F.
4) Tower size varies inversely with wet-bulb temperature. When heat load, range, and approach values are fixed, reducing the design wet-bulb temperature increases the size of the tower. See **Figure 7**. This is because most of the heat transfer in a cooling tower occurs by virtue of evaporation (which extracts approximately 1000 Btu's for every pound of water evaporated), and air's ability to absorb moisture reduces with temperature.

FIGURE 6

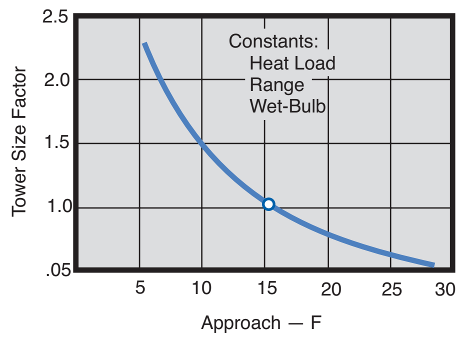
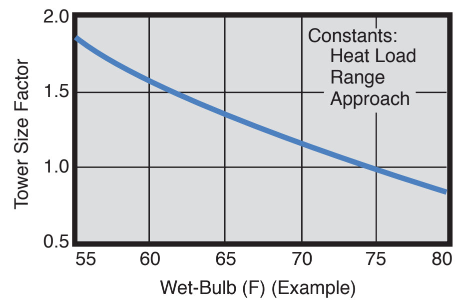


FIGURE 7



ENTHALPY EXCHANGE VISUALIZED

To understand the exchange of total heat that takes place in a cooling tower, let's assume a tower designed to cool 120 gpm (1000 lb/min) of water from 85°F to 70°F at a design wet-bulb temperature of 65°F and (for purposes of illustration only) a coincident dry-bulb temperature of 78°F. (These air conditions are defined as point 1 on **Figure 2**) Let's also assume that air is caused to move through the tower at the rate of 1000 lb/min (approximately 13,500 cfm). Since the mass flows of air and water are equal, one pound of air can be said to contact one pound of water and the psychrometric path of one such pound of air has been traced on **Figure 2** as it moves through the tower.

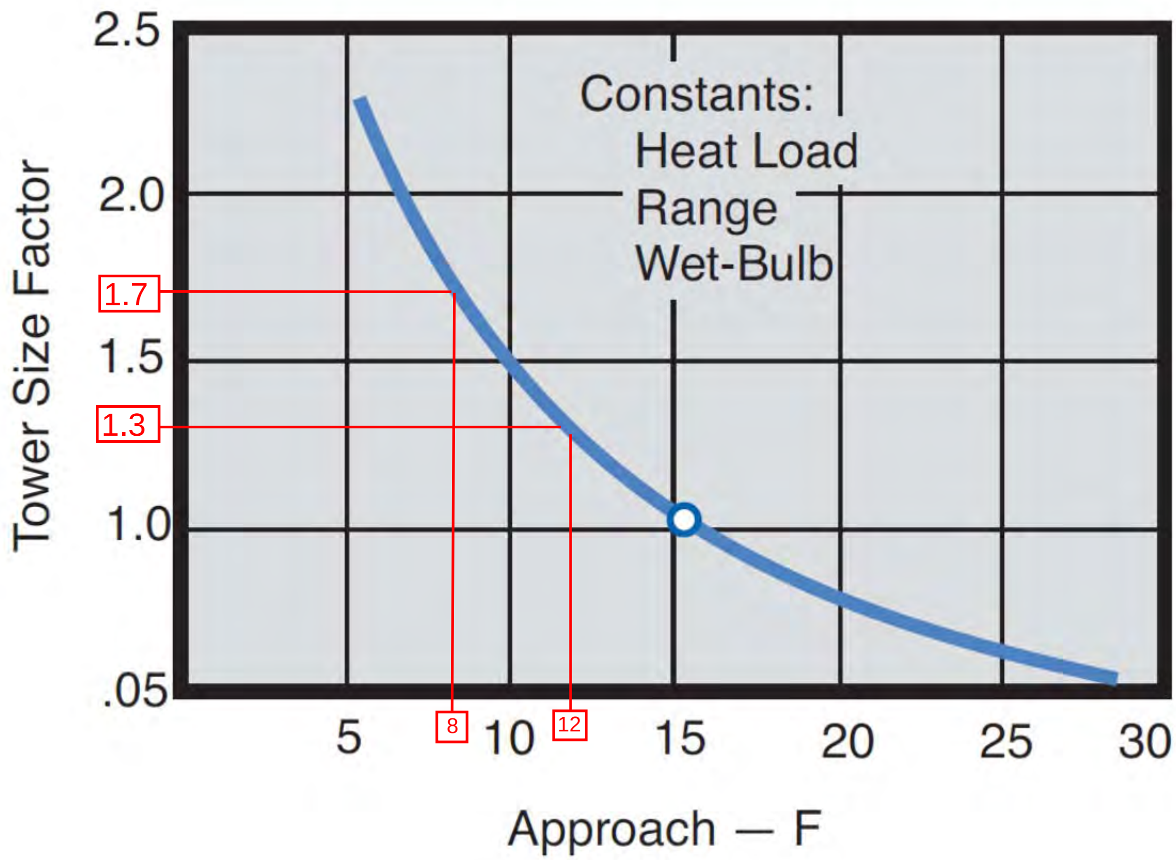
Air enters the tower at condition 1 (65°F wet-bulb and 78°F dry-bulb) and begins to gain enthalpy (total heat) and moisture content in an effort to achieve equilibrium with the water. This pursuit of equilibrium (solid line) continues until the air exits the tower at condition 2. The dashed lines identify the following changes in the psychrometric properties of this pound of air due to its contact with the water:

– Total heat content (enthalpy) increased from 30.1 Btu to 45.1 Btu. This enthalpy increase of 15 Btu was gained from the water. Therefore, one pound of water was reduced in temperature by the required amount of 15°F (85-70). See page 1.
– The air's moisture content increased from 72 grains to 163 grains (7000 grains = 1 lb). These 91 grains of moisture (0.013 lbs. of water) were evaporated from the water at a latent heat of vaporization of about 1000 Btu/lb. This means that about 13 of the 15 Btu's removed from the water (about 86% of the total) occurred by virtue of evaporation. (The latent heat of vaporization of water varies with temperature, from about 1075 Btu/lb at 32°F to 970 Btu/lb at 212°F. Actual values at specific temperatures are tabulated in various thermodynamics manuals.)

At a given rate of air moving through a cooling tower, the extent of heat transfer which can occur depends upon the amount of water surface exposed to that air. In the tower depicted in **Figure 1**, total exposure consists of the cumulative surface areas of a multitude of random sized droplets, the size of which depends largely upon the pressure at which the water is sprayed. Higher pressure will produce a finer spray—and greater total surface area exposure. However, droplets contact each other readily in the overlapping spray patterns and, of course, coalesce into larger droplets, which reduces the net surface area exposure. Consequently, predicting the thermal performance of a spray-filled tower is difficult at best, and is highly dependent upon good nozzle design as well as a constant water pressure.

Subsequent issues will deal with water distribution system arrangements used in other types of towers, along with the various types of "fills" utilized to increase water surface area exposure and enhance thermal performance.

Effect of Increasing Approach Temperature from 12 oF to 13.5 oF: 12% Reduction in Tower Size



Refined Calculations on Closed-Cycle Conversion Effect on Steam Cycle Thermal Efficiency

A. Estimated Steam Turbine Backpressure for Once-Thru Cooling on Unit 4 at Summertime Peak/Average Conditions:

1. Peak day backpressure 8/15/02: load = 235 MW, water in T = 83 °F, water out T = 99 °F, steam sat. T = 105 °F.
Backpressure = **2.25 inches Hg**.

2. Actual average Unit 4 spring, summer, fall steam turbine backpressure:

Parameter	May	June	July	August	Sept.	October	
average load, MW	196	201	211	219	217	224	Average MW Unit 4 load 2001-2004 for month indicated. Rated load is 235 MW per NYDEC air permit.
average cooling water flowrate, gpm	150,000	150,000	150,000	150,000	150,000	125,000	All three C.W. pumps in operation in May, June, July, August, and September. Assume only two pumps online beginning in second half of October.
average monthly river temperature, °F	59	69	80	82	77	67	Source of information is "Danskammer Circulating Cooling Water System Daily Operating Report," January - Dec. 2002.
average temperature increase across condenser, °F	13	14	14	15	15	16	Source of information is "Danskammer Circulating Cooling Water System Daily Operating Report," January - Dec. 2002.
TTD between warm water out and steam saturation T, °F	6	6	6	6	6	6	6 °F is surface condenser terminal temperature difference (TTD) identified in Micheletti and Burns paper presented at EPA *Symposium on Technologies for Protecting Aquatic Organisms from Cooling Water Intake Structures* , May 2003, Arlington, VA.
steam saturation temperature, °F	78	89	100	103	98	89	Sum of cooling water temperature into condenser, cooling water T increase across condenser, and delta T between warm cooling water out temperature and steam saturation temperature.
average steam turbine backpressure, in. Hg	**1.0**	**1.4**	**1.9**	**2.1**	**1.8**	**1.5**	Conversion of steam saturation temperature to steam turbine backpressure per steam tables for saturated steam.

Refined Calculations on Closed-Cycle Conversion Effect on Steam Cycle Thermal Efficiency

B. Estimated Steam Turbine Backpressure with Wet Tower Retrofit on Unit 4 at Summertime Peak/Average Conditions:

1. Backpressure at design conditions : load = 235 MW, WB = 76 °F, approach T = 13 °F, range = 20 °F, TTD = 6 °F, steam saturation T = 115 °F. Backpressure = **3.0 inches Hg**.

2. Projected actual average Unit 4 spring, summer, fall backpressure with closed-cycle wet tower.

Parameter	May	June	July	August	Sept.	October	
average load, MW	196	201	211	219	217	224	Average MW Unit 4 load 2001-2004 for month indicated. Rated load is 235 MW per NYDEC air permit.
average monthly cooling water flowrate, gpm	110,000	110,000	110,000	110,000	110,000	110,000	Six F-488-6.0-6 plume-abated wet cells at 110,000 gpm per Marley SPX 10/11/05 and 10/12/05 clarifications.
mean monthly wet bulb temperature, °F	52	62	67	66	59	48	These are mean monthly wet bulb temperature for Newburgh, NY, period of record 1973-1995.
Effective approach temperature, °F	22	17.5	16	16.5	19.5	26	Marley SPX estimates 13 °F approach temperature for six F488-6.0-6 cells with 9-bladed fans with 250 hp motors for 1,100 MMBtu/hr heat rejection duty at 235 MW output. Effective approach temperature at 200 MW is 12 °F per 11/1/05 Marley wet bulb vs. range vs. approach temperature graph for Unit 4 cooling tower. Approach temperature increases as wet bulb temperature drops per Marley 11/1/05 graph (attached).
increase in cooling water temperature across condenser (range)	16.5	17	18	18.5	18.5	19	Unit 4 rated output is 235 MW (2,512 MMBtu/hr heat input). The range is 20 oF when heat rejection duty is 1,100 MMBtu/hr at 235 MW. Range is proportionate lower as load and heat duty drop (as long as tower flowrate is maintained at 110,000 gpm).
TTD between warm water out and steam saturation T, °F	6	6	6	6	6	6	6 oF is surface condenser terminal temperature difference (TTD) identified in Micheletti and Burns paper presented at EPA *Symposium on Technologies for Protecting Aquatic Organisms from Cooling Water Intake Structures*, May 2003, Arlington, VA.
steam condensation temperature, °F	96.5	102.5	107	107	103	99	Sum of cooling water temperature into condenser, cooling water T increase across condenser, and delta T between warm water out temperature and steam saturation temperature.
average steam turbine backpressure, in. Hg	**1.7**	**2.1**	**2.4**	**2.4**	**2.1**	**1.9**	Conversion of steam condensation temperature to steam turbine backpressure per steam tables for saturated steam.

Refined Calculations on Closed-Cycle Conversion Effect on Steam Cycle Thermal Efficiency

C. Annual Unit 4 Turbine Heat Rate (Efficiency) Penalty Resulting from Conversion to Closed-Cycle Wet Cooling:
(from GE exhaust pressure correction factor graph, Attachment B-2, Chp. 5, proposed Phase II TDD)

Month	Existing once-through cooling steam turbine backpressure		Closed-cycle wet cooling steam turbine backpressure		
	Backpressure (inches Hg)	Efficiency penalty (%)	Backpressure (inches Hg)	Efficiency penalty (%)	Net efficiency penalty of closed-cycle cooling (%)
January	<1.5	0.0	<1.5	0.0	0.0
February	<1.5	0.0	<1.5	0.0	0.0
March	<1.5	0.0	<1.5	0.0	0.0
April	<1.5	0.0	1.7	0.2	0.2
May	1.0	0.0	1.7	0.2	0.2
June	1.4	0.0	2.1	0.6	0.6
July	1.9	0.4	2.4	1.0	0.6
August	2.1	0.6	2.4	1.0	0.4
September	1.8	0.3	2.1	0.6	0.3
October	1.5	0.0	1.9	0.4	0.4
November	<1.5	0.0	<1.5	0.0	0.0
December	<1.5	0.0	<1.5	0.0	0.0
				Annual average:	**0.2**

Note: GE exhaust pressure correction factors for a fossil fuel steam turbine indicate maximum heat rate (turbine efficiency) is achieved between 1.0 and 1.5 inches Hg backpressure. Turbine efficiency degrades below 1.0 inch Hg and above 1.5 inches Hg following the flatest exhaust pressure correction factor curve for fossil fuel plant steam turbines (attached).

Refined Calculations on Closed-Cycle Conversion Effect on Steam Cycle Thermal Efficiency

D. Peak Unit 4 Turbine Heat Rate Penalty Resulting from Conversion to Closed-Cycle Wet Cooling:
(from GE exhaust pressure correction factor graph, Attachment B-2, Chp. 5, proposed Phase II TDD)

Peak once-through cooling steam turbine backpressure		**Peak closed-cycle wet cooling steam turbine backpressure**		
Backpressure (inches Hg)	Efficiency penalty (%)	Backpressure (inches Hg)	Efficiency penalty (%)	**Peak efficiency penalty of closed-cycle cooling (%)**
2.25	0.75	3.0	2.25	**1.5**

Marley BEST™ Version 2.41
Product Data: 6/27/2005

Optimization 1.opt
Revised 11/1/2005 10:05:12 AM by Joe Padilla

Attachment C

Customer

Contact

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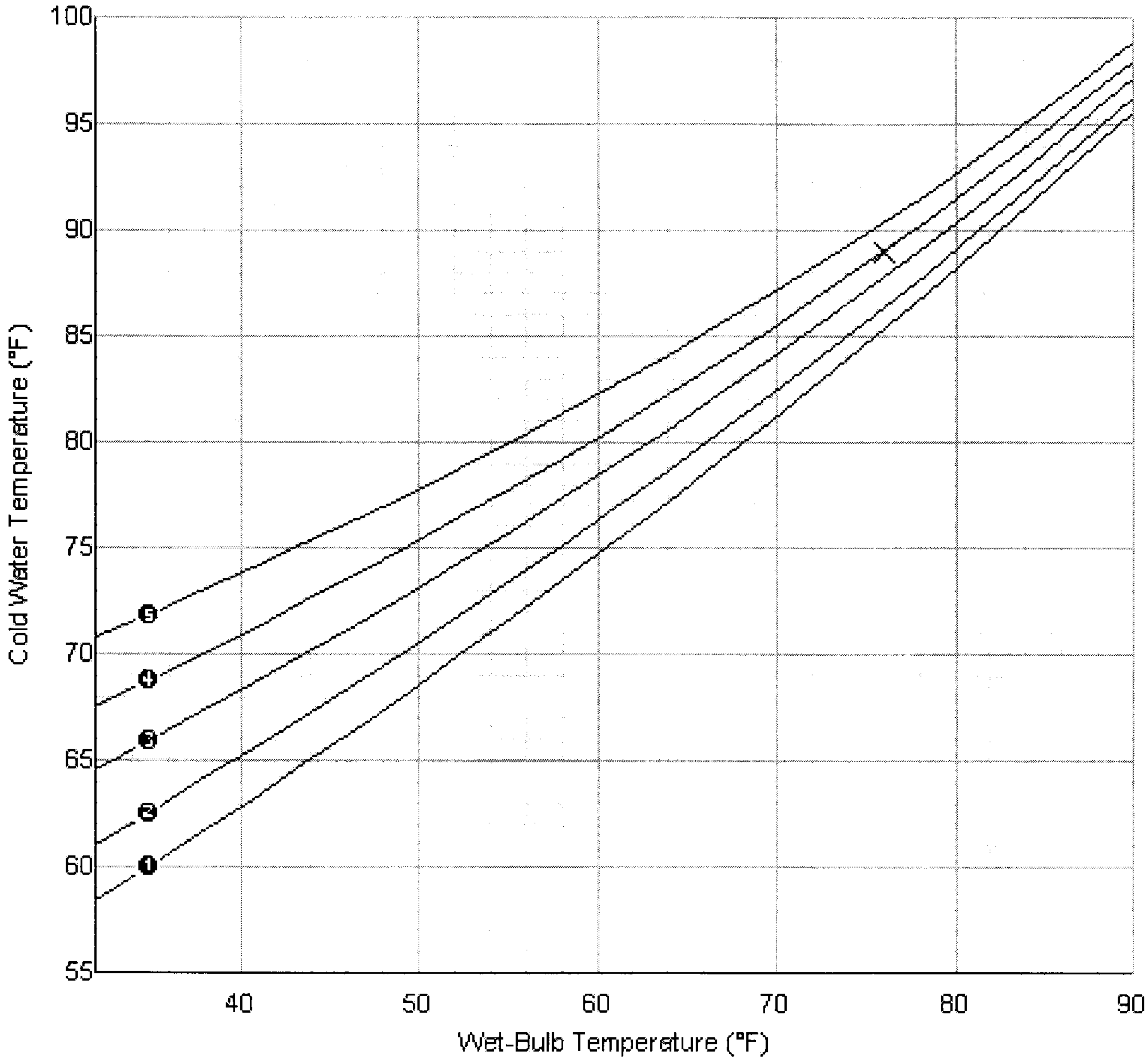


Definition

Model (ID 13)	F489A-4.0-8		
Fill	MC75 Log-4.0		
Eliminator	TU12C		
Louver	No louvers		
Fan	330HP7-9		
Stack	330"x14' Rflx/V Rib		
Speed Reducer	4000, 13.24:1		
Drive	301 Shaft		
Motor	1800 rpm, TEFC		
Closed Sides	0	Partitions	Yes
Closed Ends	2	Wind Walls	Yes
Air Inlet Guide	No		
Effective Air Inlet Ht.		10.00 ft	
Plenum Height		7.69 ft	

Design Conditions

Tower Water Flow	110000 gpm
Hot Water Temperature	109.00 °F
Cold Water Temperature	89.00 °F
Wet-Bulb Temperature	76.00 °F
Relative Humidity	50 %
Total Dissolved Solids	0 ppm
Altitude	0 ft
Inlet P.D. Vel. Heads	0
Outlet P.D. Vel. Heads	0
Motor Output	241 BHp

Curve Conditions

Tower Water Flow (100 %)	110000 gpm
Fan Speed (100 %)	134 rpm
Motor Output	241 BHp

Legend

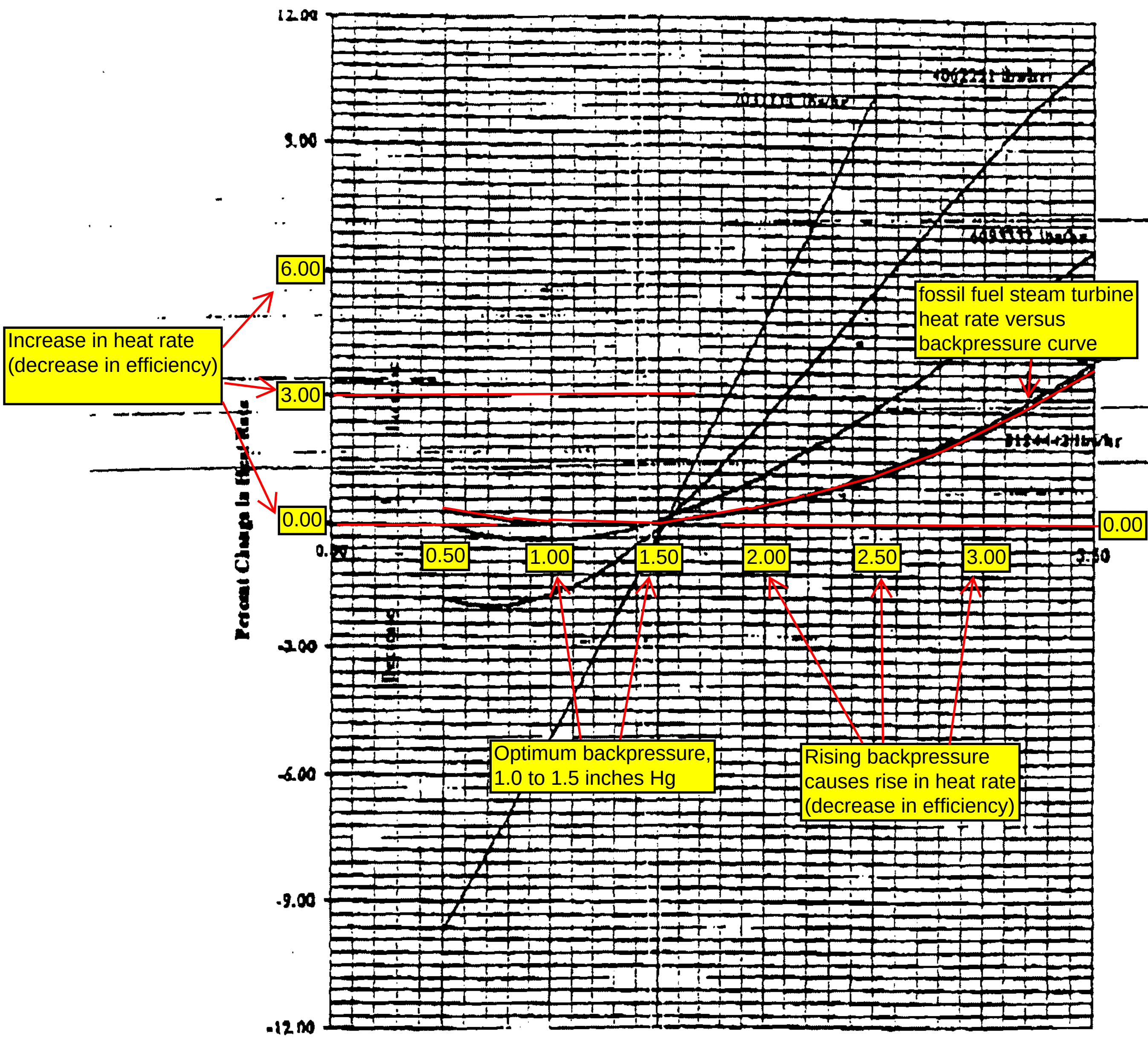
1. 12 °F Range
2. 14 °F Range
3. 17 °F Range
4. 20 °F Range
5. 24 °F Range

X Design Point

Attachment C

Fossil Fuel Steam Turbine Exhaust Pressure Correction Factor Curve from: Proposed 316(b) Phase II Technical Development Document, Chapter 5, Attachment B-2

Exhaust Pressure Correction Factors



Method of Using Curve

Flows near curves are throttle flows at 987 psia and 1191.2 Btu/lb. These correction factors assume constant control valve opening. Apply the corrections to heat rates and kW loads at 1.5 In HgA and 0.5% MU.

The percent change in kW load for various exhaust pressures is equal to:

$$\frac{(\text{Minus \% Change in Heat Rate})100}{(100 + \text{\% Change in Heat Rate})}$$

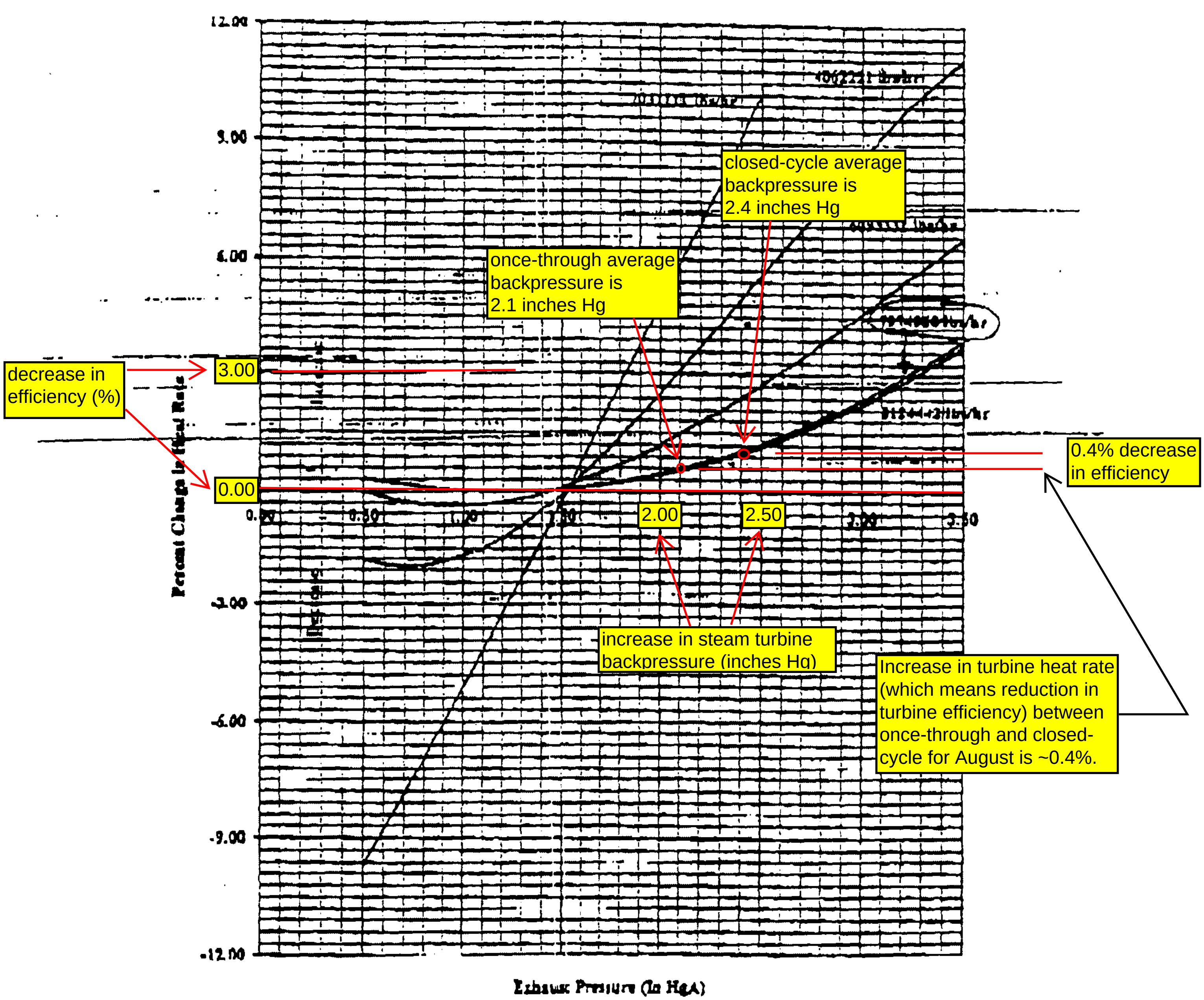
These correction factors are not guaranteed.

GE, Schenectady, New York TB # 170X341 367HB259 Rev 1 1/25/94

August Net Efficiency Penalty of Closed-Cycle Cooling Compared to Existing Once-Through Cooling

closed-cycle monthly average backpressure: 2.4 inches Hg
once-through monthly average backpressure: 2.1 inches Hg

Exhaust Pressure Correction Factors



<u>Method of Using Curve</u>

Flows near curves are throttle flows at 987 psia and 1191.2 Btu/lb. These correction factors assume constant control valve opening. Apply the corrections to heat rates and kW loads at 1.5 In HgA and 0.5% MU.
The percent change in kW load for various exhaust pressures is equal to:

$$\frac{(\text{Minus \% Change in Heat Rate})100}{(100 + \text{\% Change in Heat Rate})}$$

These correction factors are not guaranteed.
GE, Schenectady, New York TB # 170X341 367HB259 Rev 1 1/25/94

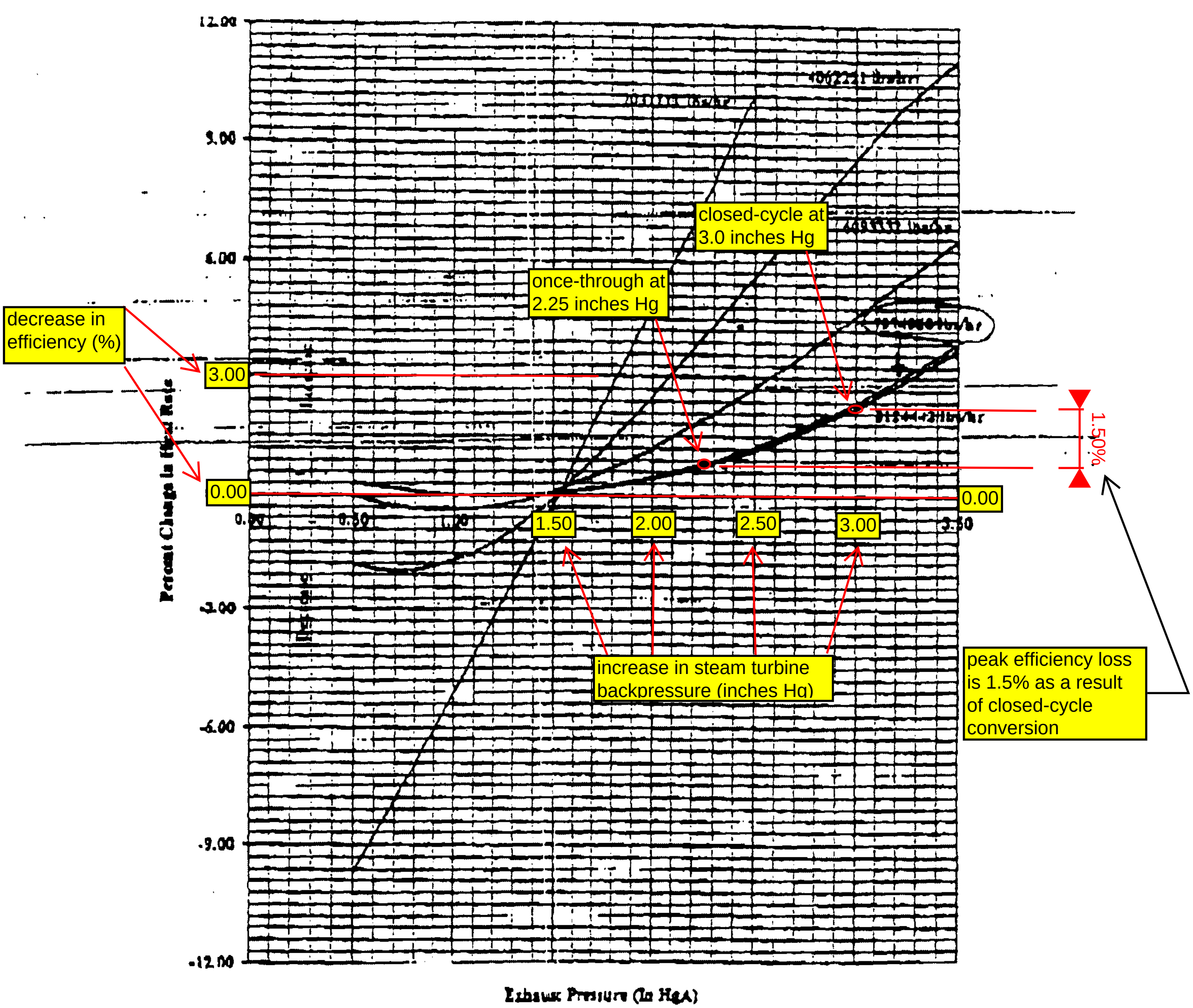
Attachment C

Peak Efficiency Penalty of Closed-Cycle Cooling Compared to Existing Once-Through Cooling

August 15, 2002

closed-cycle backpressure: 3.0 inches Hg
once-through backpressure: 2.25 inches Hg

Exhaust Pressure Correction Factors



Method of Using Curve

Flows near curves are throttle flows at 987 psia and 1191.2 Btu/lb. These correction factors assume constant control valve opening. Apply the corrections to heat rates and kW loads at 1.5 In HgA and 0.5% MU.
The percent change in kW load for various exhaust pressures is equal to:

$$\frac{(\textit{Minus \% Change in Heat Rate})100}{(100 + \% \textit{ Change in Heat Rate})}$$

These correction factors are not guaranteed.

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Attachment C

B. Powers
10/31/05

Steam Turbine Backpressure vs. Steam Saturation Temperature

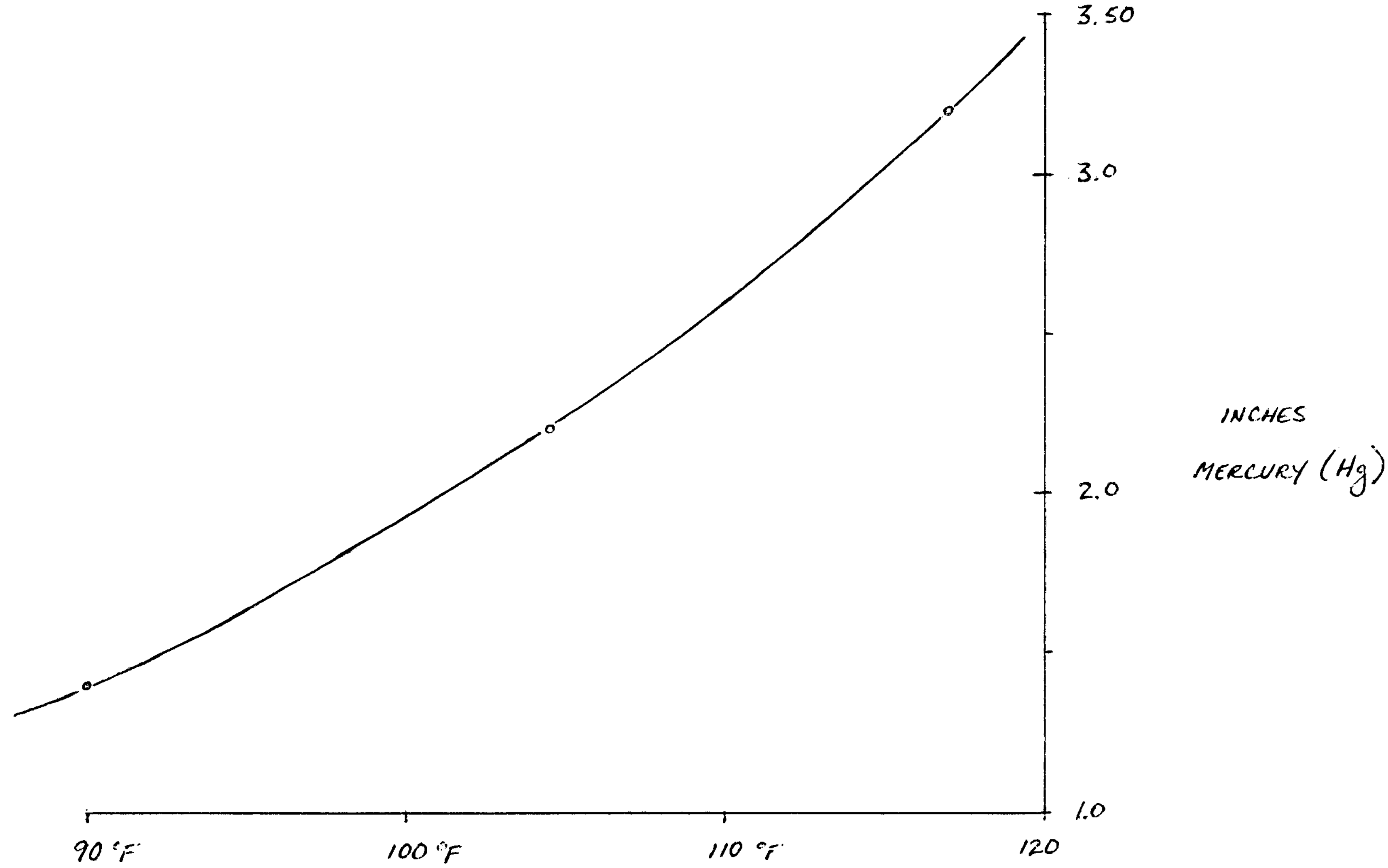
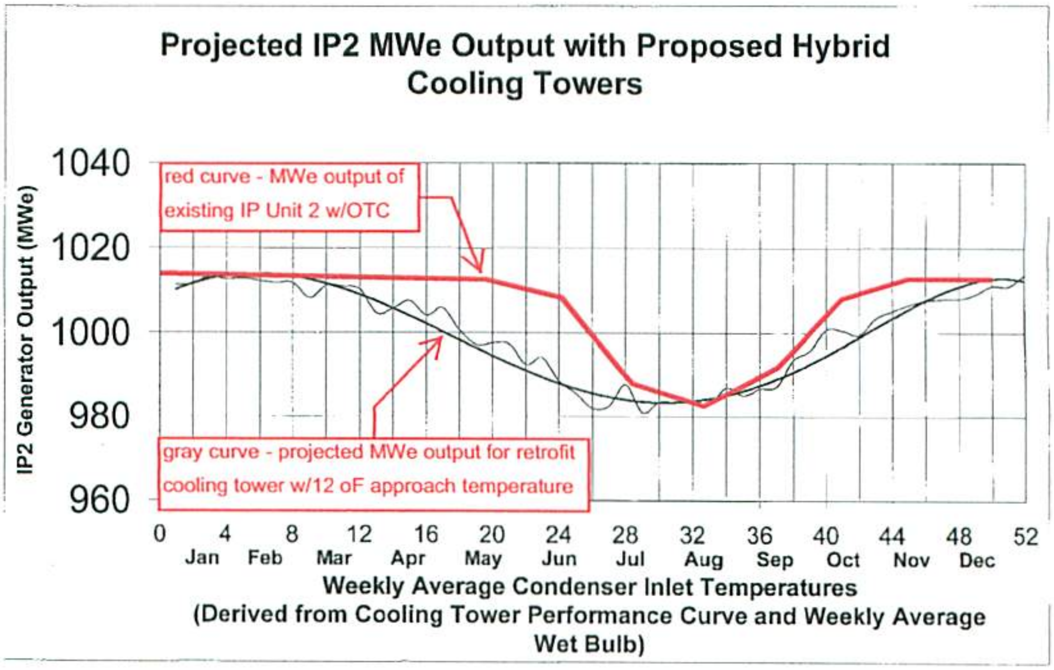
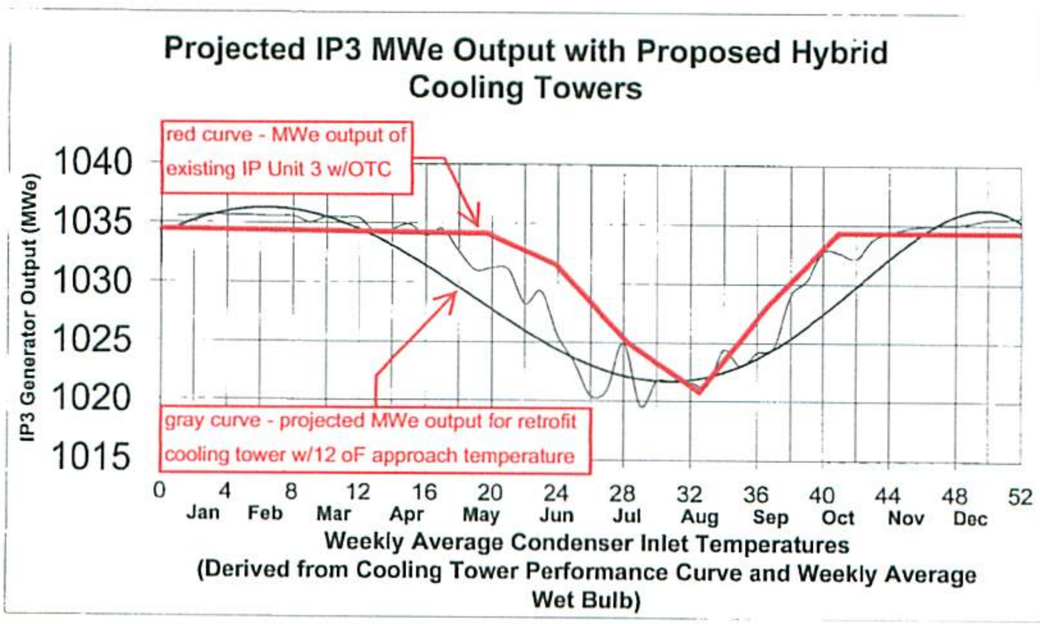


Figure 3.7 – IP2 Average Monthly Generator Output w/ Hybrid Cooling Towers



The weekly average wet bulb temperature is based upon Station meteorological data over the period of 1998 through 2000. This data is utilized to derive the corresponding weekly average condenser inlet temperature for each unit, based on the cooling tower performance curves for the proposed hybrid towers [Attachment 1, Marley Data].

Figure 3.8 – IP3 Average Monthly Generator Output w/ Hybrid Cooling Towers



Figures 3.4 and 3.5 indicate the relative impact of river water temperature on generator output for each unit.

Figure 3.4 – Indian Point 2 Generator Output vs. River Water Temperature

(100% Power, 85% Condenser Clean, ~1 DegF Condensate Subcooling, Fast CW Pump Speed)

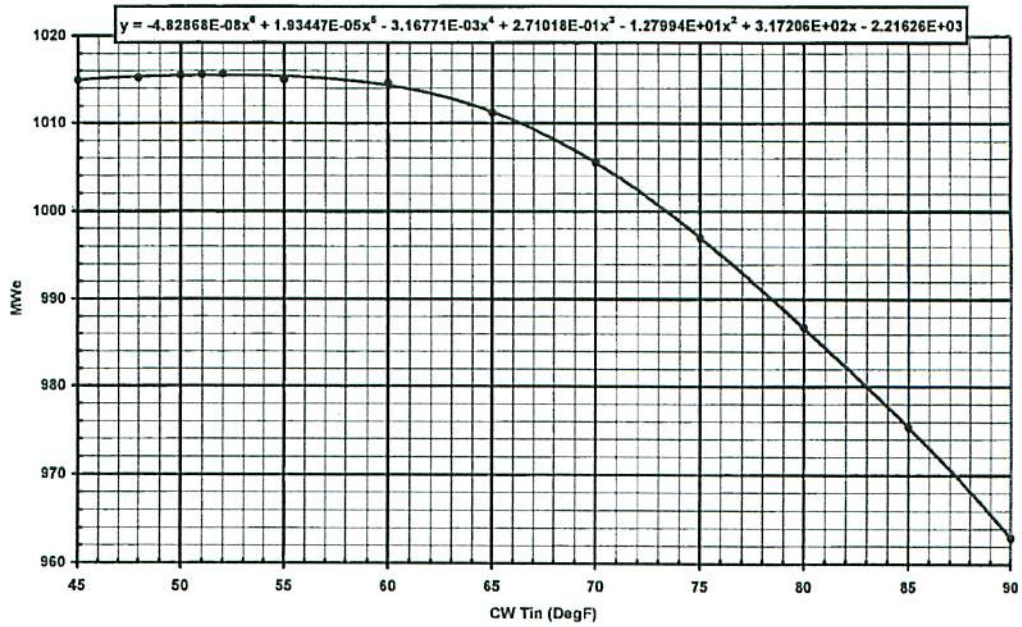


Figure 3.5 – Indian Point 3 Generator Output vs. River Water Temperature

(100% Power, 90% Condenser Clean, 1 DegF Condensate Subcooling, 360 RPM CW Pump Speed)

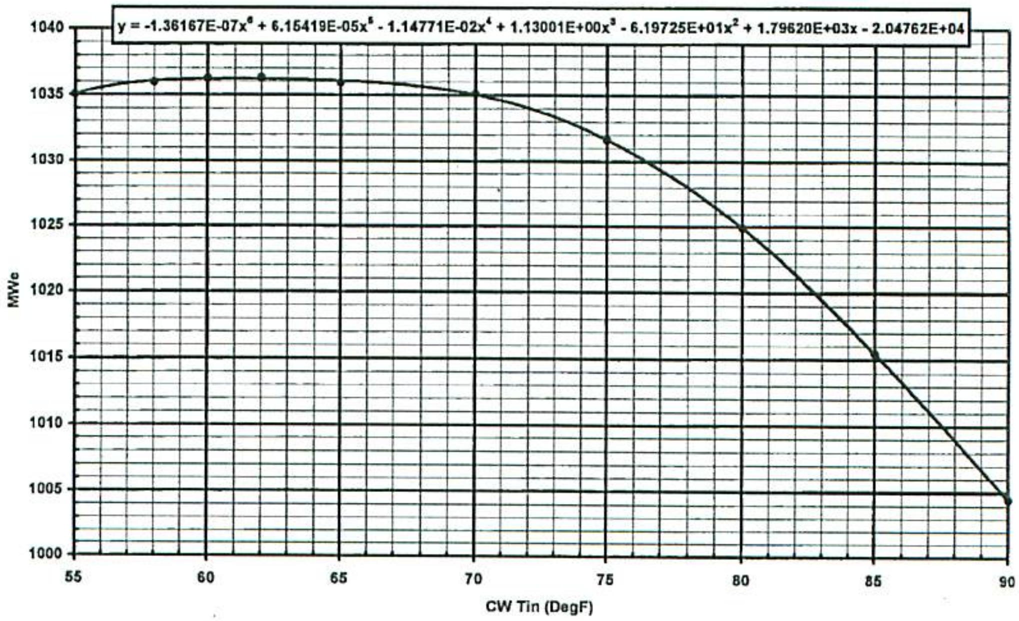


Table D-1. Effect of Hudson River Water Temperature on Gross MW Output. Indian Point Units 2 and 3

Month	Average Hudson River water temperature (°F)	Indian Point Unit 2 gross output (MW_e)	Indian Point Unit 3 gross output (MW_e)
January	< 60	1,015	1,036
February	< 60	1,015	1,036
March	< 60	1,015	1,036
April	< 60	1,015	1,036
May	< 60	1,015	1,036
June	69	1,010	1,035
July	80	986	1,021
August	82	982	1,025
September	77	993	1,029
October	67	1,008	1,036
November	< 60	1,015	1,036
December	< 60	1,015	1,036

Note: River water temperature data is for Danskammer Generating Station. 20 miles upriver from Indian Point, for calendar year 2002. See river water temperature data in Attachment C. Water temperature on June 1st was 60 °F. Water temperature on October 31st was less than 60 °F.

Table D-2. Difference Between Gross MW Output of Indian Point Units 2 and 3 with Existing OTC System and Gross MW Output Following Cooling Tower Conversion

Month	Indian Point Unit 2 (MW_e)	Indian Point Unit 3 (MW_e)
January	0	0
February	0	0
March	2	0
April	8	2
May	18	5
June	20	7
July	5	3
August	0	-1
September	4	4
October	10	5
November	5	1
December	0	0
Annual average turbine efficiency penalty, MW	5.2	2.2
Annual average turbine efficiency penalty, %	0.51[a]	0.21[b]

a) Unit 2 annual average turbine efficiency penalty = (5.2 MW/1,015 MW) = 0.0051 (0.51 percent)
b) Unit 3 annual average turbine efficiency penalty = (2.2 MW/1,036 MW) = 0.0021 (0.21 percent)

Exhibit E

Cooling Tower Capital Cost and Energy Penalty Calculations

Table 1. EPA cost estimate for wet inline tower, 10 °F approach, 20 °F range

Cooling tower type	Flowrate (gpm)	Cooling tower retrofit capital cost cost (1999 $)	Intake/ discharge piping piping modifications ($)	Inflation multiplier, 1999 - 2009	2009 EPA retrofit cooling tower capital cost ($)	
					($)	($/gpm)
wet inline, Redwood, fresh water	417,000	53.55	1.955	1.37	76	182

source: 2002 TDD, p. 2-32 to p. 2-36 and p. 5-30. EPA explains on p. 5-30 "The data did, however, indicate a median approach of 10 °F (average 10.4 °F) and a median range of 20 °F (average 21.1 °F). This range value is consistent with the value assumed in other EPA analyses and therefore a range of 20 °F will be used.

Table 1. SPX June 2009 cost estimate for wet and plume-abated back-to-back towers, 12 °F approach, 20 °F range

Cooling tower type	Flowrate (gpm)	Capital cost (2009 $)	New unit cost ($/gpm)	EPA retrofit multiplier	Retrofit capital cost including retrofit multiplier	
					($)	($/gpm)
standard wet, back-to-back, fresh water	830,000	145.6	175	1.2	175	211
plume-abated, back-to-back, fresh water	830,000	218.3	263	1.2	262	316
standard wet, back-to-back, salt water	830,000	154.4	186	1.2	185	223
plume-abated, back-to-back, salt water	830,000	231.4	279	1.2	278	335

SPX 2009 back-to-back cooling tower quote statement: Estimates are adjusted for premium hardware and California seismic requirements.

Exhibit E

Cooling Tower Capital Cost and Energy Penalty Calculations

Table 2. SPX cost data modified for 8 °F approach in Southeast sites, 1.3x cooling tower size multiplier

Cooling tower type	Flowrate (gpm)	Capital cost × 1.3 (2009 $)	New unit cost, 8 °F approach ($/gpm)	EPA retrofit multiplier	Retrofit capital cost including retrofit multiplier ($)	Retrofit capital cost including retrofit multiplier ($/gpm)
standard wet, back-to-back, fresh water	830,000	189	228	1.2	227	274
plume-abated,	830,000	284	342	1.2	341	410
standard wet, back-to-back, salt water	830,000	201	242	1.2	241	290
plume-abated, back-to-back, salt water	830,000	301	362	1.2	361	435

Table 3. U.S. average retrofit wet and plume-abated back-to-back tower cost, assuming 25% of plant capacity in Southeast

Tower type	Southeast capacity multiplier	Southeast unit cost ($/gpm)	Rest-of-nation capacity multiplier	Rest-of-nation unit cost ($/gpm)	U.S. average retrofit capital cost ($/gpm)
standard wet, inline, fresh water (EPA)	10 °F design approach temperature is composite for all regions based on 2002 TDD Table AA-1, pdf p. 216.				182
plume-abated, back-to-back, fresh water	0.25	410	0.75	316	340

Note: There is a difference of ~5 percent in the capital cost of cooling towers of similar design in fresh water and salt water applications.

Table 4. U.S. average retrofit cooling tower cost, assuming 25% of towers are plume-abated, back-to-back

Tower type	Plume-abated multiplier	Plume-abated unit cost ($/gpm)	Standard wet inline tower multiplier	Wet inline tower unit cost ($/gpm)	U.S. average retrofit capital cost ($/gpm)

75% wet inline, 25% plume-abated back-to-back	0.25	340	0.75	182	222

Table 5. Capital cost of cooling tower retrofits at nuclear and fossil boiler OTC plants, all effected U.S. units retrofit by 2012

Plant type	OTC flowrate, 210 x 10^9 gal/day fossil		Optimized cooling tower flowrate,		Total U.S. cooling tower capital cost
	gal/day x 10^9	gpm x 10^6	gal/day x 10^9	gpm x 10^6	(\$ x 10^9)
nuclear	70	49	53	36	8.1
fossil boiler	210	146	158	109	24.2
				Total capital cost (billions):	32.3

EIA, Annual Energy Outlook 2011, April 2011, p. 48. "The Electric Power Research Institute (EPRI) has estimated that 312 gigawatts of capacity currently in operation (252 gigawatts of fossil fuel capacity and 60 gigawatts of nuclear capacity) would be affected by [a closed-cycle cooling] rule." Fossil OTC demand: 252,000 MW x 35,000 gallons/MWh x 24 hour = ~210 billion gallons per day. Nuclear OTC demand: 60,000 MW x 48,000 gallons/MWh x 24 hour = ~70 billion gallons per day.

March 2011 Phase II TDD, p. 8.33: "EPA developed the existing facility retrofit costs using existing flow data and cost equations that used cooling flow in gpm as the basis. . . These cooling water requirements assume that the typical existing plant design includes a once-through cooling system with a condenser temperature rise (ΔT) of 15 oF, and that the closed-cycle cooling system that replaces a once-though system will be optimized using a ΔT of 20 oF." Powers Engineering comment - The amount of heat absorbed by the circulating cooling water is a function of flowrate in gpm x the rise in circulating water temperature across the surface condenser in oF. The reduction in circulating water flowrate in a retrofit closed-cycle cooling system relative to the original OTC system is inversely proportional to the increase in the rise in water temperature increase across the surface condenser ("range"). Therefore, the average circulating water flow reduction with a closed-cycle cooling retrofit is: OTC flowrate x (15 oF/20 oF) = 0.75 x OTC flowrate.

EPA, Economic and Benefits Analysis for Proposed 316(b) Existing Facilities Rule, March 2011, p. 3-18. Cooling tower cost recovery based on 30 years, 7 percent.

BILL POWERS, P.E.

PROFESSIONAL HISTORY

Powers Engineering, San Diego, CA 1994-
ENSR Consulting and Engineering, Camarillo, CA 1989-93
Naval Energy and Environmental Support Activity, Port Hueneme, CA 1982-87
U.S. Environmental Protection Agency, Research Triangle Park, NC 1980-81

EDUCATION

Master of Public Health – Environmental Sciences, University of North Carolina
Bachelor of Science – Mechanical Engineering, Duke University

PROFESSIONAL AFFILIATIONS

Registered Professional Mechanical Engineer, California (Certificate M24518)
American Society of Mechanical Engineers
Air & Waste Management Association

TECHNICAL SPECIALTIES

Twenty-five years of experience in:

- Power plant air emission control system and cooling system assessments
- Combustion equipment permitting, testing and monitoring
- Air pollution control equipment retrofit design/performance testing
- Petroleum refinery air engineering and testing
- Oil and gas emission inventory development
- Latin America environmental project experience

POWER PLANT AIR EMISSION CONTROL AND COOLING SYSTEM CONVERSION ASSESSMENTS

Utility Boilers – Correlation Between Opacity and PM_{10} Emissions at Coal-Fired Plant. Provided expert testimony on whether correlation existed between mass PM_{10} emissions and opacity during opacity excursions at large coal-fired boiler in Georgia. EPA and EPRI technical studies were reviewed to assess the correlation of opacity and mass emissions during opacity levels below and above 20 percent. A strong correlation between opacity and mass emissions was apparent at a sister plant at opacities less than 20 percent. The correlation suggests that the opacity monitor correlation underestimates mass emissions at opacities greater than 20 percent, but may continue to exhibit a good correlation for the component of mass emissions in the PM_{10} size range.

Utility Boilers – Correlation Between Opacity and PM_{10} at Coal-Fired Plant and Solutions. Lead engineer on evaluation of historic record at Alabama coal-fired power plant to establish a correlation between site-specific continuous opacity data and particulate source test data. Sufficient data was available to establish that a good correlation existed between the visible emissions limit and the permitted PM_{10} emissions limit. Solutions to opacity exceedances, including a replacement baghouse or a polishing baghouse downstream of the existing ESP, were evaluated and found to be cost-effective.

Combined-Cycle Power Plant Startup and Shutdown Emissions. Lead engineer for analysis of air permit startup and shutdown emissions minimization for combined-cycle power plant proposed for the San Francisco Bay Area. Original equipment was specified for baseload operation prior to suspension of project in early 2000s. Operational profile described in revised air permit was load following with potential for daily start/stop. Recommended that either fast start turbine technology be employed to minimize start/stop emissions or that "demonstrated in practice" operational and control software modifications be employed to minimize startup/shutdown emissions.

Biomass Plant NO_x and CO Air Emissions Control Evaluation. Lead engineer for evaluation of available NO_x and CO controls for a 45 MW biomass plant in Texas where proponent had identified selective non-catalytic reduction (SNCR) and good combustion practices as BACT. Identified the use of tail-end SCR for NO_x control at several operational U.S. biomass plants, and oxidation catalyst in use at two of these plants for CO and VOC control, as BACT for the proposed biomass plant.

IGCC as BACT for Air Emissions from Proposed 960 MW Coal Plant. Presented testimony on IGCC as BACT for air emissions reduction from 960 MW coal plant. Applicant received air permit for a pulverized coal plant to be equipped with a baghouse, wet scrubber, and wet ESP for air emissions control. Use of IGCC technology at the emission rates permitted for two recently proposed U.S. IGCC projects, and demonstrated in practice at a Japanese IGCC plant firing Chinese bituminous coal, would substantially reduce potential emissions of NO_x, SO_2, and PM. The estimated control cost-effectiveness of substituting IGCC for pulverized coal technology in this case was approximately $3,000/ton.

Analysis of Proposed Air Emission Limits for 600 MW Pulverized Coal Plant. Project engineer tasked with evaluating sufficiency of air emissions limits and control technologies for proposed 600 MW coal plant Arkansas. Determined that the applicant had: 1) not properly identified SO_2, sulfuric acid mist, and PM BACT control levels for the plant, and 2) improperly utilized an incremental cost effectiveness analysis to justify air emission control levels that did not represent BACT.

Eight Pulverized Coal Fired 900 MW Boilers – IGCC Alternative with Air Cooling. Provided testimony on integrated gasification combined cycle (IGCC) as a fully commercial coal-burning alternative to the pulverized coal (PC) technology proposed by TXU for eight 900 MW boilers in East Texas, and East Texas as an ideal location for CO2 sequestration due to presence of mature oilfield CO2 enhanced oil recovery opportunities and a deep saline aquifer underlying the entire region. Also presented testimony on the major increase in regional consumptive water use that would be caused by the evaporative cooling towers proposed for use in the PC plants, and that consumptive water use could be lowered by using IGCC with evaporative cooling towers or by using air-cooled condensers with PC or IGCC technology. TXU ultimately dropped plans to build the eight PC plants as a condition of a corporate buy-out.

Utility Boilers – Conversion of Existing Once-Through Cooled Boilers to Wet Towers, Parallel Wet-Dry Cooling, or Dry Cooling. Provided expert testimony and preliminary design for the conversion of four natural gas and/or coal-fired utility boilers (Unit 4, 235 MW; Unit 3, 135 MW; Unit 2, 65 MW; and Unit 1,65 MW) from once-through river water cooling to wet cooling towers, parallel wet-dry cooling, and dry cooling. Major design constraints were available land for location of retrofit cooling systems and need to maintain maximum steam turbine backpressure at or below 5.5 inches mercury to match performance capabilities of existing equipment. Approach temperatures of 12 ^oF and 13 ^oF were used for the wet towers. SPX Cooling Technologies F-488 plume-abated wet cells with six feet of packing were used to achieve approach temperatures of 12 ^oF and 13 ^oF. Annual energy penalty of wet tower retrofit designs is approximately 1 percent. Parallel wet-dry or dry cooling was determined to be technically feasible for Unit 3 based on straightforward access to the Unit 3 surface condenser and available land adjacent to the boiler.

Utility Boiler – Assessment of Air Cooling and Integrated Gasification/Combined Cycle for Proposed 500 MW Coal-Fired Plant. Provided expert testimony on the performance of air-cooling and IGCC relative to the conventional closed-cycle wet cooled, supercritical pulverized coal boiler proposed by the applicant. Steam Pro™ coal-fired power plant design software was used to model the proposed plant and evaluate the impacts on performance of air cooling and plume-abated wet cooling. Results indicated that a conservatively designed air-cooled condenser could maintain rated power output at the design ambient temperature of 90 ^oF. The IGCC comparative analysis indicated that unit reliability comparable to a conventional pulverized coal unit could be achieved by including a spare gasifier in the IGCC design, and that the slightly higher capital cost of IGCC was offset by greater thermal efficiency and reduced water demand and air emissions.

Utility Boiler – Assessment of Closed-Cycle Cooling Retrofit Cost for 1,200 MW Oil-Fired Plant. Prepared an assessment of the cost and feasibility of a closed-cycle wet tower retrofit for the 1,200 MW Roseton Generating Station. Determined that the cost to retrofit the Roseton plant with plume-abated closed-cycle wet cooling was well established based on cooling tower retrofit studies performed by the original owner (Central Hudson Gas & Electric Corp.) and subsequent regulatory agency critique of the cost estimate. Also determined that elimination of redundant and/or excessive budgetary line items in owners cost estimate brings the closed-cycle retrofit in line with expected costs for comparable new or retrofit plume-abated cooling tower applications.

Nuclear Power Plant – Assessment of Closed-Cycle Cooling Retrofit Cost for 2,000 MW Plant. Prepared an assessment of the cost and feasibility of a closed-cycle wet tower retrofit for the 2,000 MW Indian Point Generating Station. Determined that the most appropriate arrangement for the hilly site would be an inline plume-abated wet tower instead of the round tower configuration analyzed by the owner. Use of the inline configuration would allow placement of the towers at numerous sites on the property with little or need for blasting of bedrock, greatly reducing the cost of the retrofit. Also proposed an alternative circulating cooling water piping configuration to avoid the extensive downtime projected by the owner for modifications to the existing discharge channel.

Kentucky Coal-Fired Power Plant – Pulverized Coal vs IGCC. Expert witness in Sierra Club lawsuit against Peabody Coal Company's plan to construct a 1,500 MW pulverized-coal fired power plant in Kentucky. Presented case that Integrated Gasification Combined Cycle (IGCC) is a superior method for producing power from coal, from environmental and energy efficiency perspective, than the proposed pulverized-coal plant. Presented evidence that IGCC is technically feasible and cost competitive with pulverized coal.

Power Plant Dry Cooling Symposium – Chair and Organizer. Chair and organizer of the first symposium held in the U.S. (May 2002) that focused exclusively on dry cooling technology for power plants. Sessions included basic principles of wet and dry cooling systems, performance capabilities of dry cooling systems, case studies of specific installations, and reasons why dry cooling is the predominant form of cooling specified in certain regions of North America (Massachusetts, Nevada, northern Mexico). All technical papers presented at the symposium are available at http://awmasandiego.org/SDC-2002/.

Utility Boiler – Best Available NO_x Control System for 525 MW Coal-Fired Circulating Fluidized Bed Boiler Plant. Expert witness in dispute over whether 50 percent NO_x control using selective non-catalytic reduction (SNCR) constituted BACT for a proposed 525 MW circulating fluidized bed (CFB) boiler plant. Presented testimony that SNCR was capable of continuous NO_x reduction of greater than 70 percent on a CFB unit and that tail-end selective catalytic reduction (SCR) was technically feasible and could achieve greater than 90 percent NO_x reduction.

Utility Boilers – Retrofit of SCR and FGD to Existing Coal-Fired Units. Expert witness in successful effort to compel an existing coal-fired power plant located in Massachusetts to meet an accelerated NO_x and SO_2 emission control system retrofit schedule. Plant owner argued the installation of advanced NO_x and SO_2 control systems would generate > 1 ton/year of ancillary emissions, such as sulfuric acid mist, and that under Massachusetts Dept. of Environmental Protection regulation ancillary emissions > 1 ton/year would require a BACT evaluation and a two-year extension to retrofit schedule. Successfully demonstrated that no ancillary emissions would be generated if the retrofit NO_x and SO_2 control systems were properly sized and optimized. Plant owner committed to accelerated compliance schedule in settlement agreement.

COMBUSTION EQUIPMENT PERMITTING, TESTING AND MONITORING

EPRI Gas Turbine Power Plant Permitting Documents – Co-Author.
Co-authored two Electric Power Research Institute (EPRI) gas turbine power plant siting documents. Responsibilities included chapter on state-of-the-art air emission control systems for simple-cycle and combined-cycle gas turbines, and authorship of sections on dry cooling and zero liquid discharge systems.

Air Permits for 50 MW Peaker Gas Turbines – Six Sites Throughout California.
Responsible for preparing all aspects of air permit applications for five 50 MW FT-8 simple-cycle turbine installations at sites around California in response to emergency request by California state government for additional peaking power. Units were designed to meet 2.0 ppm NO_x using standard temperature SCR and innovative dilution air system to maintain exhaust gas temperature within acceptable SCR range. Oxidation catalyst is also used to maintain CO below 6.0 ppm.

Kauai 27 MW Cogeneration Plant – Air Emission Control System Analysis. Project manager to evaluate technical feasibility of SCR for 27 MW naphtha-fired turbine with once-through heat recovery steam generator. Permit action was stalled due to questions of SCR feasibility. Extensive analysis of the performance of existing oil-fired turbines equipped with SCR, and bench-scale tests of SCR applied to naphtha-fired turbines, indicated that SCR would perform adequately. Urea was selected as the SCR reagent given the wide availability of urea on the island. Unit is first known application of urea-injected SCR on a naphtha-fired turbine.

Microturbines – Ronald Reagan Library, Ventura County, California.
Project manager and lead engineer or preparation of air permit applications for microturbines and standby boilers. The microturbines drive the heating and cooling system for the library. The microturbines are certified by the manufacturer to meet the 9 ppm NO_x emission limit for this equipment. Low-NO_x burners are BACT for the standby boilers.

Hospital Cogeneration Microturbines – South Coast Air Quality Management District.
Project manager and lead engineer for preparation of air permit application for three microturbines at hospital cogeneration plant installation. The draft Authority To Construct (ATC) for this project was obtained two weeks after submittal of the ATC application. 30-day public notification was required due to the proximity of the facility to nearby schools. The final ATC was issued two months after the application was submitted, including the 30-day public notification period.

Gas Turbine Cogeneration – South Coast Air Quality Management District. Project manager and lead engineer for preparation of air permit application for two 5.5 MW gas turbines in cogeneration configuration for county government center. The turbines will be equipped with selective catalytic reduction (SCR) and oxidation catalyst to comply with SCAQMD BACT requirements. Aqueous urea will be used as the SCR reagent to avoid trigger hazardous material storage requirements. A separate permit will be obtained for the NO_x and CO continuous emissions monitoring systems. The ATCs is pending.

Industrial Boilers – NO_x BACT Evaluation for San Diego County Boilers.
Project manager and lead engineer for preparation of Best Available Control Technology (BACT) evaluation for three industrial boilers to be located in San Diego County. The BACT included the review of low NO_x burners, FGR, SCR, and low temperature oxidation (LTO). State-of-the-art ultra low NO_x burners with a 9 ppm emissions guarantee were selected as NO_x BACT for these units.

Peaker Gas Turbines – Evaluation of NO_x Control Options for Installations in San Diego County.
Lead engineer for evaluation of NO_x control options available for 1970s vintage simple-cycle gas turbines proposed for peaker sites in San Diego County. Dry low-NO_x (DLN) combustors, catalytic combustors, high-temperature SCR, and NO_x absorption/conversion (SCONO$_x$) were evaluated for each candidate turbine make/model. High-temperature SCR was selected as the NOx control option to meet a 5 ppm NO_x emission requirement.

Hospital Cogeneration Plant Gas Turbines – San Joaquin Valley Unified Air Pollution Control District. Project manager and lead engineer for preparation of air permit application and Best Available Control Technology (BACT) evaluation for hospital cogeneration plant installation. The BACT included the review of DLN combustors, catalytic combustors, high-temperature SCR and $SCONO_x$. DLN combustion followed by high temperature SCR was selected as the NO_x control system for this installation. The high temperature SCR is located upstream of the heat recovery steam generator (HRSG) to allow the diversion of exhaust gas around the HRSG without compromising the effectiveness of the NO_x control system.

1,000 MW Coastal Combined-Cycle Power Plant – Feasibility of Dry Cooling. Expert witness in on-going effort to require use of dry cooling on proposed 1,000 MW combined-cycle "repower" project at site of an existing 1,000 MW utility boiler plant. Project proponent argued that site was two small for properly sized air-cooled condenser (ACC) and that use of ACC would cause 12-month construction delay. Demonstrated that ACC could easily be located on the site by splitting total of up to 80 cells between two available locations at the site. Also demonstrated that an ACC optimized for low height and low noise would minimize or eliminate proponent claims of negative visual and noise impacts.

Industrial Cogeneration Plant Gas Turbines – Upgrade of Turbine Power Output. Project manager and lead engineer for preparation of Best Available Control Technology (BACT) evaluation for proposed gas turbine upgrade. The BACT included the review of DLN combustors, catalytic combustors, high-, standard-, and low-temperature SCR, and $SCONO_x$. Successfully negotiated air permit that allowed facility to initially install DLN combustors and operate under a NO_x plantwide "cap." Within two major turbine overhauls, or approximately eight years, the NO_x emissions per turbine must be at or below the equivalent of 5 ppm. The 5 ppm NO_x target will be achieved through technological in-combustor NO_x control such as catalytic combustion, or SCR or SCR equivalent end-of-pipe NO_x control technologies if catalytic combustion is not available.

Gas Turbines – Modification of RATA Procedures for Time-Share CEM. Project manager and lead engineer for the development of alternate CO continuous emission monitor (CEM) Relative Accuracy Test Audit (RATA) procedures for time-share CEM system serving three 7.9 MW turbines located in San Diego. Close interaction with San Diego APCD and EPA Region 9 engineers was required to receive approval for the alternate CO RATA standard. The time-share CEM passed the subsequent annual RATA without problems as a result of changes to some of the CEM hardware and the more flexible CO RATA standard.

Gas Turbines – Evaluation of NO_x Control Technology Performance. Lead engineer for performance review of dry low-NO_x combustors, catalytic combustors, high-, standard-, and low-temperature selective catalytic reduction (SCR), and NO_x absorption/conversion ($SCONO_x$). Major turbine manufacturers and major manufacturers of end-of-pipe NO_x control systems for gas turbines were contacted to determine current cost and performance of NO_x control systems. A comparison of 1993 to 1999 "$/kwh" and "$/ton" cost of these control systems was developed in the evaluation.

Gas Turbines – Evaluation of Proposed NO_x Control System to Achieve 3 ppm Limit. Lead engineer for evaluation for proposed combined cycle gas turbine NO_x and CO control systems. Project was in litigation over contract terms, and there was concern that the GE Frame 7FA turbine could not meet the 3 ppm NO_x permit limit using a conventional combustor with water injection followed by SCR. Operations personnel at GE Frame 7FA installatins around the country were interviewed, along with principal SCR vendors, to corroborate that the installation could continuously meet the 3 ppm NO_x limit.

Gas Turbines – Title V "Presumptively Approvable" Compliance Assurance Monitoring Protocol. Project manager and lead engineer for the development of a "presumptively approval" NO_x parametric emissions monitoring system (PEMS) protocol for industrial gas turbines. "Presumptively approvable" means that any gas turbine operator selecting this monitoring protocol can presume it is acceptable to the U.S. EPA. Close interaction with the gas turbine manufacturer's design engineering staff and the U.S. EPA Emissions Measurement Branch (Research Triangle Park, NC) was required to determine modifications necessary to the current PEMS to upgrade it to "presumptively approvable" status.

Environmental Due Diligence Review of Gas Turbine Sites – Mexico. Task leader to prepare regulatory compliance due diligence review of Mexican requirements for gas turbine power plants. Project involves eleven potential sites across Mexico, three of which are under construction. Scope involves identification of all environmental, energy sales, land use, and transportation corridor requirements for power projects in Mexico. Coordinator of Mexican environmental subcontractors gathering on-site information for each site, and translator of Spanish supporting documentation to English.

Development of Air Emission Standards for Gas Turbines - Peru. Served as principal technical consultant to the Peruvian Ministry of Energy in Mines (MEM) for the development of air emission standards for Peruvian gas turbine power plants. All major gas turbine power plants in Peru are currently using water injection to increase turbine power output. Recommended that 42 ppm on natural gas and 65 ppm on diesel (corrected to 15% O_2) be established as the NO_x limit for existing gas turbine power plants. These limits reflect NO_x levels readily achievable using water injection at high load. Also recommended that new gas turbine sources be subject to a BACT review requirement.

Gas Turbines – Title V Permit Templates. Lead engineer for the development of standardized permit templates for approximately 100 gas turbines operated by the oil and gas industry in the San Joaquin Valley. Emissions limits and monitoring requirements were defined for units ranging from GE Frame 7 to Solar Saturn turbines. Stand-alone templates were developed based on turbine size and NO_x control equipment. NO_x utilized in the target turbine population ranged from water injection alone to water injection combined with SCR.

Gas Turbines – Evaluation of NO_x, SO_2 and PM Emission Profiles. Performed a comparative evaluation of the NO_x, SO_2 and particulate (PM) emission profiles of principal utility-scale gas turbines for an independent power producer evaluating project opportunities in Latin America. All gas turbine models in the 40 MW to 240 MW range manufactured by General Electric, Westinghouse, Siemens and ABB were included in the evaluation.

Stationary Internal Combustion Engine (ICE) RACT/BARCT Evaluation. Lead engineer for evaluation of retrofit NO_x control options available for the oil and gas production industry gas-fired ICE population in the San Joaquin Valley affected by proposed RACT and BARCT emission limits. Evaluation centered on lean-burn compressor engines under 500 bhp, and rich-burn constant and cyclically loaded (rod pump) engines under 200 bhp. The results of the evaluation indicated that rich burn cyclically-loaded rod pump engines comprised 50 percent of the affected ICE population, though these ICEs accounted for only 5 percent of the uncontrolled gas-fired stationary ICE NO_x emissions. Recommended retrofit NO_x control strategies included: air/fuel ratio adjustment for rod pump ICEs, Non-selective catalytic reduction (NSCR) for rich-burn, constant load ICEs, and "low emission" combustion modifications for lean burn ICEs.

Development of Air Emission Standards for Stationary ICEs - Peru. Served as principal technical consultant to the Peruvian Ministry of Energy in Mines (MEM) for the development of air emission standards for Peruvian stationary ICE power plants. Draft 1997 World Bank NO_x and particulate emission limits for stationary ICE power plants served as the basis for proposed MEM emission limits. A detailed review of ICE emissions data provided in PAMAs submitted to the MEM was performed to determine the level of effort that would be required by Peruvian industry to meet the proposed NO_x and particulate emission limits. The draft 1997 WB emission limits were revised to reflect reasonably achievable NO_x and particulate emission limits for ICEs currently in operation in Peru.

Air Toxics Testing of Natural Gas-Fired ICEs. Project manager for test plan/test program to measure volatile and semi-volatile organic air toxics compounds from fourteen gas-fired ICEs used in a variety of oil and gas production applications. Test data was utilized by oil and gas production facility owners throughout California to develop accurate ICE air toxics emission inventories.

AIR ENGINEERING/AIR TESTING PROJECT EXPERIENCE – GENERAL

Reverse Air Fabric Filter Retrofit Evaluation – Coal-Fired Boiler. Lead engineer for upgrade of reverse air fabric filters serving coal-fired industrial boilers. Fluorescent dye injected to pinpoint broken bags and damper leaks. Corrosion of pneumatic actuators serving reverse air valves and inadequate insulation identified as principal causes of degraded performance.

Pulse-Jet Fabric Filter Performance Evaluation – Gold Mine. Lead engineer on upgrade of pulse-jet fabric filter and associated exhaust ventilation system serving an ore-crushing facility at a gold mine. Fluorescent dye used to identify bag collar leaks, and modifications were made to pulse air cycle time and duration. This marginal source was in compliance at 20 percent of emission limit following completion of repair work.

Pulse-Jet Fabric Filter Retrofit - Gypsum Calciner. Lead engineer on upgrade of pulse-jet fabric filter controlling particulate emissions from a gypsum calciner. Recommendations included a modified bag clamping mechanism, modified hopper evacuation valve assembly, and changes to pulse air cycle time and pulse duration.

Wet Scrubber Retrofit – Plating Shop. Project engineer on retrofit evaluation of plating shop packed-bed wet scrubbers failing to meet performance guarantees during acceptance trials, due to excessive mist carryover. Recommendations included relocation of the mist eliminator (ME), substitution of the original chevron blade ME with a mesh pad ME, and use of higher density packing material to improve exhaust gas distribution. Wet scrubbers passed acceptance trials following completion of recommended modifications.

Electrostatic Precipitator (ESP) Retrofit Evaluation – MSW Boiler. Lead engineer for retrofit evaluation of single field ESP on a municipal solid waste (MSW) boiler. Recommendations included addition of automated power controller, inlet duct turning vanes, and improved collecting plate rapping system.

ESP Electric Coil Rapper Vibration Analysis Testing - Coal-Fired Boiler. Lead engineer for evaluation of ESP rapper effectiveness test program on three field ESP equipped with "magnetically induced gravity return" (MIGR) rappers. Accelerometers were placed in a grid pattern on ESP collecting plates to determine maximum instantaneous plate acceleration at a variety of rapper power setpoints. Testing showed that the rappers met performance specification requirements.

Aluminum Remelt Furnace Particulate Emissions Testing. Project manager and lead engineer for high temperature (1,600 ^oF) particulate sampling of a natural gas-fired remelt furnace at a major aluminum rolling mill. Objectives of test program were to: 1) determine if condensable particulate was present in stack gases, and 2) to validate the accuracy of the in-stack continuous opacity monitor (COM). Designed and constructed a customized high temperature (inconel) PM_{10}/Mtd 17 sampling assembly for test program. An onsite natural gas-fired boiler was also tested to provide comparative data for the condensable particulate portion of the test program. Test results showed that no significant levels of condensable particulate in the remelt furnace exhaust gas, and indicated that the remelt furnace and boiler had similar particulate emission rates. Test results also showed that the COM was accurate.

Aluminum Remelt Furnace CO and NO_x Testing. Project manager and lead engineer for continuous week-long testing of CO and NO_x emissions from aluminum remelt furnace. Objective of test program was to characterize CO and NO_x emissions from representative remelt furnace for use in the facility's criteria pollution emissions inventory. A TECO Model 48 CO analyzer and a TECO Model 10 NO_x analyzer were utilized during the test program to provide $\pm$1 ppm measurement accuracy, and all test data was recorded by an automated data acquisition system.

PETROLEUM REFINERY AIR ENGINEERING/TESTING EXPERIENCE

Big West Refinery Expansion EIS. Lead engineer on comparative cost analysis of proposed wet cooling tower and fin-fan air cooler for process cooling water for the proposed clean fuels expansion project at the Big West Refinery in Bakersfield, California. Selection of the fin-fin air-cooler would eliminate all consumptive water use and wastewater disposal associated with the cooling tower. Air emissions of VOC and PM_{10} would be reduced with the fin-fan air-cooler even though power demand of the air-cooler is incrementally higher than that of the cooling tower. Fin-fan air-coolers with approach temperatures of 10 ^oF and 20 ^oF were evaluated. The annualized cost of the fin-fin air-cooler with a 20 ^oF approach temperature is essentially the same as that of the cooling tower when the cost of all ancillary cooling tower systems are considered.

Criteria and Air Toxic Pollutant Emissions Inventory for Proposed Refinery Modifications. Project manager and technical lead for development of baseline and future refinery air emissions inventories for process modifications required to produce oxygenated gasoline and desulfurized diesel fuel at a California refinery. State of the art criteria and air toxic pollutant emissions inventories for refinery point, fugitive and mobile sources were developed. Point source emissions estimates were generated using onsite criteria pollutant test data, onsite air toxics test data, and the latest air toxics emission factors from the statewide refinery air toxics inventory database. The fugitive volatile organic compound (VOC) emissions inventories were developed using the refinery's most recent inspection and maintenance (I&M) monitoring program test data to develop site-specific component VOC emission rates. These VOC emission rates were combined with speciated air toxics test results for the principal refinery process streams to produce fugitive VOC air toxics emission rates. The environmental impact report (EIR) that utilized this emission inventory data was the first refinery "Clean Fuels" EIR approved in California.

Development of Air Emission Standards for Petroleum Refinery Equipment - Peru. Served as principal technical consultant to the Peruvian Ministry of Energy in Mines (MEM) for the development of air emission standards for Peruvian petroleum refineries. The sources included in the scope of this project included: 1) SO_2 and NO_x refinery heaters and boilers, 2) desulfurization of crude oil, particulate and SO_2 controls for fluid catalytic cracking units (FCCU), 3) VOC and CO emissions from flares, 4) vapor recovery systems for marine unloading, truck loading, and crude oil/refined products storage tanks, and 5) VOC emissions from process fugitive sources such as pressure relief valves, pumps, compressors and flanges. Proposed emission limits were developed for new and existing refineries based on a thorough evaluation of the available air emission control technologies for the affected refinery sources. Leading vendors of refinery control technology, such as John Zink and Exxon Research, provided estimates of retrofit costs for the largest Peruvian refinery, La Pampilla, located in Lima. Meetings were held in Lima with refinery operators and MEM staff to discuss the proposed emission limits and incorporate mutually agreed upon revisions to the proposed limits for existing Peruvian refineries.

Air Toxic Pollutant Emissions Inventory for Existing Refinery. Project manager and technical lead for air toxic pollutant emissions inventory at major California refinery. Emission factors were developed for refinery heaters, boilers, flares, sulfur recovery units, coker deheading, IC engines, storage tanks, process fugitives, and catalyst regeneration units. Onsite source test results were utilized to characterize emissions from refinery combustion devices. Where representative source test results were not available, AP-42 VOC emission factors were combined with available VOC air toxics speciation profiles to estimate VOC air toxic emission rates. A risk assessment based on this emissions inventory indicated a relatively low health risk associated with refinery operations. Benzene, 1,3-butadiene and PAHs were the principal health risk related pollutants emitted.

Air Toxics Testing of Refinery Combustion Sources. Project manager for comprehensive air toxics testing program at a major California refinery. Metals, Cr^{+6}, PAHs, H_2S and speciated VOC emissions were measured from refinery combustion sources. High temperature Cr^{+6} stack testing using the EPA Cr^{+6} test method was performed for the first time in California during this test program. Representatives from the California Air Resources Board source test team performed simultaneous testing using ARB Method 425 (Cr^{+6}) to compare the results of EPA and ARB Cr^{+6} test methodologies. The ARB approved the test results generated using the high temperature EPA Cr^{+6} test method.

Air Toxics Testing of Refinery Fugitive Sources. Project manager for test program to characterize air toxic fugitive VOC emissions from fifteen distinct process units at major California refinery. Gas, light liquid, and heavy liquid process streams were sampled. BTXE, 1,3-butadiene and propylene concentrations were quantified in gas samples, while BTXE, cresol and phenol concentrations were measured in liquid samples. Test results were combined with AP-42 fugitive VOC emission factors for valves, fittings, compressors, pumps and PRVs to calculate fugitive air toxics VOC emission rates.

OIL AND GAS PRODUCTION AIR ENGINEERING/TESTING EXPERIENCE

Air Toxics Testing of Oil and Gas Production Sources. Project manager and lead engineer for test plan/test program to determine VOC removal efficiency of packed tower scrubber controlling sulfur dioxide emissions from a crude oil-fired steam generator. Ratfisch 55 VOC analyzers were used to measure the packed tower scrubber VOC removal efficiency. Tedlar bag samples were collected simultaneously to correlate BTX removal efficiency to VOC removal efficiency. This test was one of hundreds of air toxics tests performed during this test program for oil and gas production facilities from 1990 to 1992. The majority of the volatile air toxics analyses were performed at in-house laboratory. Project staff developed thorough familiarity with the applications and limitations of GC/MS, GC/PID, GC/FID, GC/ECD and GC/FPD. Tedlar bags, canisters, sorbent tubes and impingers were used during sampling, along with isokinetic tests methods for multiple metals and PAHs.

Air Toxics Testing of Glycol Reboiler – Gas Processing Plant. Project manager for test program to determine emissions of BTXE from glycol reboiler vent at gas processing facility handling 12 MM/cfd of produced gas. Developed innovative test methods to accurately quantify BTXE emissions in reboiler vent gas.

Air Toxics Emissions Inventory Plan. Lead engineer for the development of generic air toxics emission estimating techniques (EETs) for oil and gas production equipment. This project was performed for the Western States Petroleum Association in response to the requirements of the California Air Toxics "Hot Spots" Act. EETs were developed for all point and fugitive oil and gas production sources of air toxics, and the specific air toxics associated with each source were identified. A pooled source emission test methodology was also developed to moderate the cost of source testing required by the Act.

Fugitive NMHC Emissions from TEOR Production Field. Project manager for the quantification of fugitive Nonmethane hydrocarbon (NMHC) emissions from a thermally enhanced oil recovery (TEOR) oil production field in Kern County, CA. This program included direct measurement of NMHC concentrations in storage tank vapor headspace and the modification of available NMHC emission factors for NMHC-emitting devices in TEOR produced gas service, such as wellheads, vapor trunklines, heat exchangers, and compressors. Modification of the existing NMHC emission factors was necessary due to the high concentration of CO_2 and water vapor in TEOR produced gases.

Fugitive Air Emissions Testing of Oil and Gas Production Fields. Project manager for test plan/test program to determine VOC and air toxics emissions from oil storage tanks, wastewater storage tanks and produced gas lines. Test results were utilized to develop comprehensive air toxics emissions inventories for oil and gas production companies participating in the test program.

Oil and Gas Production Field – Air Emissions Inventory and Air Modeling. Project manager for oil and gas production field risk assessment. Project included review and revision of the existing air toxics emission inventory, air dispersion modeling, and calculation of the acute health risk, chronic non-carcinogenic risk and carcinogenic risk of facility operations. Results indicated that fugitive H_2S emissions from facility operations posed a potential health risk at the facility fenceline.

TITLE V PERMIT APPLICATION/MONITORING PLAN EXPERIENCE

Title V Permit Application – San Diego County Industrial Facility. Project engineer tasked with preparing streamlined Title V operating permit for U.S. Navy facilities in San Diego. Principal emission units included chrome plating, lead furnaces, IC engines, solvent usage, aerospace coating and marine coating operations. For each device category in use at the facility, federal MACT requirements were integrated with District requirements in user friendly tables that summarized permit conditions and compliance status.

Title V Permit Application Device Templates - Oil and Gas Production Industry. Project manager and lead engineer to prepare Title V permit application "templates" for the Western States Petroleum Association (WSPA). The template approach was chosen by WSPA to minimize the administrative burden associated with listing permit conditions for a large number of similar devices located at the same oil and gas production facility. Templates are being developed for device types common to oil and gas production operations. Device types include: boilers, steam generators, process heaters, gas turbines, IC engines, fixed-roof storage tanks, fugitive components, flares, and cooling towers. These templates will serve as the core of Title V permit applications prepared for oil and gas production operations in California.

Title V Permit Application - Aluminum Rolling Mill. Project manager and lead engineer for Title V permit application prepared for largest aluminum rolling mill in the western U.S. Responsible for the overall direction of the permit application project, development of a monitoring plan for significant emission units, and development of a hazardous air pollutant (HAP) emissions inventory. The project involved extensive onsite data gathering, frequent interaction with the plant's technical and operating staff, and coordination with legal counsel and subcontractors. The permit application was completed on time and in budget.

Title V Model Permit - Oil and Gas Production Industry. Project manager and lead engineer for the comparative analysis of regional and federal requirements affecting oil and gas production industry sources located in the San Joaquin Valley. Sources included gas turbines, IC engines, steam generators, storage tanks, and process fugitives. From this analysis, a model applicable requirements table was developed for a sample device type (storage tanks) that covered the entire population of storage tanks operated by the industry. The U.S. EPA has tentatively approved this model permit approach, and work is ongoing to develop comprehensive applicable requirements tables for each major category of sources operated by the oil and gas industry in the San Joaquin Valley.

Title V Enhanced Monitoring Evaluation of Oil and Gas Production Sources. Lead engineer to identify differences in proposed EPA Title V enhanced monitoring protocols and the current monitoring requirements for oil and gas production sources in the San Joaquin Valley. The device types evaluated included: steam generators, stationary ICEs, gas turbines, fugitives, fixed roof storage tanks, and thermally enhanced oil recovery (TEOR) well vents. Principal areas of difference included: more stringent Title V O&M requirements for parameter monitors (such as temperature, fuel flow, and O_2), and more extensive Title V recordkeeping requirements.

RACT/BARCT/BACT EVALUATIONS

BACT Evaluation of Wool Fiberglass Insulation Production Line. Project manager and lead engineer for BACT evaluation of a wool fiberglass insulation production facility. The BACT evaluation was performed as a component of a PSD permit application. The BACT evaluation included a detailed analysis of the available control options for forming, curing and cooling sections of the production line. Binder formulations, wet electrostatic precipitators, wet scrubbers, and thermal oxidizers were evaluated as potential PM_{10} and VOC control options. Low NO_x burner options and combustion control modifications were examined as potential NO_x control techniques for the curing oven burners. Recommendations included use of a proprietary binder formulation to achieve PM_{10} and VOC BACT, and use of low-NO_x burners in the curing ovens to achieve NO_x BACT. The PSD application is currently undergoing review by EPA Region 9.

RACT/BARCT Reverse Jet Scrubber/Fiberbed Mist Eliminator Retrofit Evaluation. Project manager and lead engineer on project to address the inability of existing wet electrostatic precipitators (ESPs) and atomized mist scrubbers to adequately remove low concentration submicron particulate from high volume recovery boiler exhaust gas at the Alaska Pulp Corporation mill in Sitka, AK. The project involved thorough on-site inspections of existing control equipment, detailed review of maintenance and performance records, and a detailed evaluation of potential replacement technologies. These technologies included a wide variety of scrubbing technologies where manufacturers claimed high removal efficiencies on submicron particulate in high humidity exhaust gas. Packed tower scrubbers, venturi scrubbers, reverse jet scrubbers, fiberbed mist eliminators and wet ESPs were evaluated. Final recommendations included replacement of atomized mist scrubber with reverse jet scrubber and upgrading of the existing wet ESPs. The paper describing this project was published in the May 1992 TAPPI Journal.

Aluminum Smelter RACT Evaluation - Prebake. Project manager and technical lead for CO and PM_{10} RACT evaluation for prebake facility. Retrofit control options for CO emissions from the anode bake furnace, potline dry scrubbers and the potroom roof vents were evaluated. PM_{10} emissions from the coke kiln, potline dry scrubbers, potroom roof vents, and miscellaneous potroom fugitive sources were addressed. Four CO control technologies were identified as technologically feasible for potline CO emissions: potline current efficiency improvement through the addition of underhung busswork and automated puncher/feeders, catalytic incineration, recuperative incineration and regenerative incineration. Current efficiency improvement was identified as probable CO RACT if onsite test program demonstrated the effectiveness of this approach. Five PM_{10} control technologies were identified as technologically feasible: increased potline hooding efficiency through redesign of shields, the addition of a dense-phase conveying system, increased potline air evacuation rate, wet scrubbing of roof vent emissions, and fabric filter control of roof vent emissions. The cost of these potential PM_{10} RACT controls exceeded regulatory guidelines for cost effectiveness, though testing of modified shield configurations and dense-phase conveying is being conducted under a separate regulatory compliance order.

RACT/BACT Testing/Evaluation of PM_{10} Mist Eliminators on Five-Stand Cold Mill. Project manager and lead engineer for fiberbed mist eliminator and mesh pad mist eliminator comparative pilot test program on mixed phase aerosol (PM_{10})/gaseous hydrocarbon emissions from aluminum high speed cold rolling mill. Utilized modified EPA Method 5 sampling train with portion of sample gas diverted (after particulate filter) to Ratfisch 55 VOC analyzer. This was done to permit simultaneous quantification of aerosol and gaseous hydrocarbon emissions in the exhaust gas. The mesh pad mist eliminator demonstrated good control of PM_{10} emissions, though test results indicated that the majority of captured PM_{10} evaporated in the mesh pad and was emitted as VOC.

Aluminum Remelt Furnace/Rolling Mill RACT Evaluations. Lead engineer for comprehensive CO and PM_{10} RACT evaluation for the largest aluminum sheet and plate rolling mill in western U.S. Significant sources of CO emissions from the facility included the remelt furnaces and the coater line. The potential CO RACT options for the remelt furnaces included: enhanced maintenance practices, preheating combustion air, installation of fully automated combustion controls, and energy efficiency modifications. The coater line was equipped with an afterburner for VOC and CO destruction prior to the initiation of the RACT study. It was determined that the afterburner meets or exceeds RACT requirements for the coater line. Significant sources of PM_{10} emissions included the remelt furnaces and the 80-inch hot rolling mill. Chlorine fluxing in the melting and holding furnaces was identified as the principal source of PM_{10} emissions from the remelt furnaces. The facility is in the process of minimizing/eliminating fluxing in the melting furnaces, and exhaust gases generated in holding furnaces during fluxing will be ducted to a baghouse for PM_{10} control. These modifications are being performed under a separate compliance order, and were determined to exceed RACT requirements. A water-based emulsion coolant and inertial separators are currently in use on the 80-inch hot mill for PM_{10}

control. Current practices were determined to meet/exceed PM_{10} RACT for the hot mill. Tray tower absorption/recovery systems were also evaluated to control PM_{10} emissions from the hot mill, though it was determined that the technical/cost feasibility of using this approach on an emulsion-based coolant had not yet been adequately demonstrated.

BARCT Low NO_x Burner Conversion – Industrial Boilers. Lead engineer for evaluation of low NO_x burner options for natural gas-fired industrial boilers. Also evaluated methanol and propane as stand-by fuels to replace existing diesel stand-by fuel system. Evaluated replacement of steam boilers with gas turbine co-generation system.

BACT Packed Tower Scrubber/Mist Eliminator Performance Evaluations. Project manager and lead engineer for Navy-wide plating shop air pollution control technology evaluation and emissions testing program. Mist eliminators and packed tower scrubbers controlling metal plating processes, which included hard chrome, nickel, copper, cadmium and precious metals plating, were extensively tested at three Navy plating shops. Chemical cleaning and stripping tanks, including hydrochloric acid, sulfuric acid, chromic acid and caustic, were also tested. The final product of this program was a military design specification for plating and chemical cleaning shop air pollution control systems. The hydrochloric acid mist sampling procedure developed during this program received a protected patent.

BACT Packed Tower Scrubber/UV Oxidation System Pilot Test Program. Technical advisor for pilot test program of packed tower scrubber/ultraviolet (UV) light VOC oxidation system controlling VOC emissions from microchip manufacturing facility in Los Angeles. The testing was sponsored in part by the SCAQMD's Innovative Technology Demonstration Program, to demonstrate this innovative control technology as BACT for microchip manufacturing operations. The target compounds were acetone, methylethylketone (MEK) and 1,1,1-trichloroethane, and compound concentrations ranged from 10-100 ppmv. The single stage packed tower scrubber consistently achieved greater than 90% removal efficiency on the target compounds. The residence time required in the UV oxidation system for effective oxidation of the target compounds proved significantly longer than the residence time predicted by the manufacturer.

BACT Pilot Testing of Venturi Scrubber on Gas/Aerosol VOC Emission Source. Technical advisor for project to evaluate venturi scrubber as BACT for mixed phase aerosol/gaseous hydrocarbon emissions from deep fat fryer. Venturi scrubber demonstrated high removal efficiency on aerosol, low efficiency on VOC emissions. A number of VOC tests indicated negative removal efficiency. This anomaly was traced to a high hydrocarbon concentration in the scrubber water. The pilot unit had been shipped directly to the jobsite from another test location by the manufacturer without any cleaning or inspection of the pilot unit.

Pulp Mill Recovery Boiler BACT Evaluation. Lead engineer for BACT analysis for control of SO_2, NO_x, CO, TNMHC, TRS and particulate emissions from the proposed addition of a new recovery furnace at a kraft pulp mill in Washington. A "top down" approach was used to evaluate potential control technologies for each of the pollutants considered in the evaluation.

Air Pollution Control Equipment Design Specification Development. Lead engineer for the development of detailed Navy design specifications for wet scrubbers and mist eliminators. Design specifications were based on field performance evaluations conducted at the Long Beach Naval Shipyard, Norfolk Naval Shipyard, and Jacksonville Naval Air Station. This work was performed for the U.S. Navy to provide generic design specifications to assist naval facility engineering divisions with air pollution control equipment selection. Also served as project engineer for the development of Navy design specifications for ESPs and fabric filters.

CONTINUOUS EMISSION MONITOR (CEM) PROJECT EXPERIENCE

Process Heater CO and NO_x CEM Relative Accuracy Testing. Project manager and lead engineer for process heater CO and NO_x analyzer relative accuracy test program at petrochemical manufacturing facility. Objective of test program was to demonstrate that performance of onsite CO and NO_x CEMs was in compliance with U.S. EPA "Boiler and Industrial Furnace" hazardous waste co-firing regulations. A TECO Model 48 CO analyzer and a TECO Model 10 NO_x analyzer were utilized during the test program to provide $\pm$1 ppm measurement accuracy, and all test data was recorded by an automated data acquisition system. One of the two process heater CEM systems tested failed the initial test due to leaks in the gas conditioning system. Troubleshooting was performed using O_2 analyzers, and the leaking component was identified and replaced. This CEM system met all CEM relative accuracy requirements during the subsequent retest.

Performance Audit of NO_x and SO_2 CEMs at Coal-Fired Power Plant. Lead engineer on system audit and challenge gas performance audit of NO_x and SO_2 CEMs at a coal-fired power plant in southern Nevada. Dynamic and instrument calibration checks were performed on the CEMs. A detailed visual inspection of the CEM system, from the gas sampling probes at the stack to the CEM sample gas outlet tubing in the CEM trailer, was also conducted. The CEMs passed the dynamic and instrument calibration requirements specified in EPA's Performance Specification Test - 2 (NO_x and SO_2) alternative relative accuracy requirements.

LATIN AMERICA ENVIRONMENTAL PROJECT EXPERIENCE

Preliminary Design of Ambient Air Quality Monitoring Network – Lima, Peru. Project leader for project to prepare specifications for a fourteen station ambient air quality monitoring network for the municipality of Lima, Peru. Network includes four complete gaseous pollutant, particulate, and meteorological parameter monitoring stations, as well as eight PM_{10} and TSP monitoring stations.

Evaluation of Proposed Ambient Air Quality Network Modernization Project – Venezuela. Analyzed a plan to modernize and expand the ambient air monitoring network in Venezuela. Project was performed for the U.S. Trade and Development Agency. Direct interaction with policy makers at the Ministerio del Ambiente y de los Recursos Naturales Renovables (MARNR) in Caracas was a major component of this project.

Evaluation of U.S.-Mexico Border Region Copper Smelter Compliance with Treaty Obligations – Mexico. Project manager and lead engineer to evaluate compliance of U.S. and Mexican border region copper smelters with the SO_2 monitoring, recordkeeping and reporting requirements in Annex IV [Copper Smelters] of the La Paz Environmental Treaty. Identified potential problems with current ambient and stack monitoring practices that could result in underestimating the impact of SO_2 emissions from some of these copper smelters. Identified additional source types, including hazardous waste incinerators and power plants, that should be considered for inclusion in the La Paz Treaty process.

Development of Air Emission Limits for ICE Cogeneration Plant - Panamá. Lead engineer assisting U.S. cogeneration plant developer to permit an ICE cogeneration plant at a hotel/casino complex in Panama. Recommended the use of modified draft World Bank NO_x and PM limits for ICE power plants. The modification consisted of adding a thermal efficiency factor adjustment to the draft World Bank NO_x and PM limits. These proposed ICE emission limits are currently being reviewed by Panamanian environmental authorities.

Mercury Emissions Inventory for Stationary Sources in Northern Mexico. Project manager and lead engineer to estimate mercury emissions from stationary sources in Northern Mexico. Major potential sources of mercury emissions include solid- and liquid-fueled power plants, cement kilns co-firing hazardous waste, and non-ferrous metal smelters. Emission estimates were provided for approximately eighty of these sources located in Northern Mexico. Coordinated efforts of two Mexican subcontractors, located in Mexico City and Hermosillo, to obtain process throughput data for each source included in the inventory.

Translation of U.S. EPA Scrap Tire Combustion Emissions Estimation Document – Mexico. Evaluated the Translated a U.S. EPA scrap tire combustion emissions estimation document from English to Spanish for use by Latin American environmental professionals.

Environmental Audit of Aluminum Production Facilities – Venezuela. Evaluated the capabilities of existing air, wastewater and solid/hazardous waste control systems used by the aluminum industry in eastern

Venezuela. This industry will be privatized in the near future. Estimated the cost to bring these control systems into compliance with air, wastewater and solid/hazardous waste standards recently promulgated in Venezuela. Also served as technical translator for team of U.S. environmental engineers involved in the due diligence assessment.

Assessment of Environmental Improvement Projects – Chile and Peru. Evaluated potential air, water, soil remediation and waste recycling projects in Lima, Peru and Santiago, Chile for feasibility study funding by the U.S. Trade and Development Agency. Project required onsite interaction with in-country decisionmakers (in Spanish). Projects recommended for feasibility study funding included: 1) an air quality technical support project for the Santiago, Chile region, and 2) soil remediation/metals recovery projects at two copper mine/smelter sites in Peru.

Air Pollution Control Training Course – Mexico. Conducted two-day Spanish language air quality training course for environmental managers of assembly plants in Mexicali, Mexico. Spanish-language course manual prepared by Powers Engineering. Practical laboratory included training in use of combustion gas analyzer, flame ionization detector (FID), photoionization detector (PID), and occupational sampling.

Stationary Source Emissions Inventory – Mexico. Developed a comprehensive air emissions inventory for stationary sources in Nogales, Sonora. This project requires frequent interaction with Mexican state and federal environmental authorities. The principal Powers Engineering subcontractor on this project is a Mexican firm located in Hermosillo, Sonora.

VOC Measurement Program – Mexico. Performed a comprehensive volatile organic compound (VOC) measurements program at a health products fabrication plant in Mexicali, Mexico. An FID and PID were used to quantify VOCs from five processes at the facility. Occupational exposures were also measured. Worker exposure levels were above allowable levels at several points in the main assembly area.

Renewable Energy Resource Assessment Proposal – Panama. Translated and managed winning bid to evaluate wind energy potential in Panama. Direct interaction with the director of development at the national utility monopoly (IRHE) was a key component of this project.

Comprehensive Air Emissions Testing at Assembly Plant – Mexico. Project manager and field supervisor of emissions testing for particulates, NO_x, SO_2 and CO at turbocharger/air cooler assembly plant in Mexicali, Mexico. Source specific emission rates were developed for each point source at the facility during the test program. Translated test report into Spanish for review by the Mexican federal environmental agency (SEMARNAP).

Air Pollution Control Equipment Retrofit Evaluation – Mexico. Project manager and lead engineer for comprehensive evaluation of air pollution control equipment and industrial ventilation systems in use at assembly plant consisting of four major facilities. Equipment evaluated included fabric filters controlling blast booth emissions, electrostatic precipitator controlling welding fumes, and industrial ventilation systems controlling welding fumes, chemical cleaning tank emissions, and hot combustion gas emissions. Recommendations included modifications to fabric filter cleaning cycle, preventative maintenance program for the electrostatic precipitator, and redesign of the industrial ventilation system exhaust hoods to improve capture efficiency.

Comprehensive Air Emissions Testing at Assembly Plant – Mexico. Project manager and field supervisor of emissions testing for particulates, NO_x, SO_2 and CO at automotive components assembly plant in Acuña, Mexico. Source-specific emission rates were developed for each point source at the facility during the test program. Translated test report into Spanish.

Fluent in Spanish. Studied at the Universidad de Michoacán in Morelia, Mexico, 1993, and at the Colegio de España in Salamanca, Spain, 1987-88. Have lectured (in Spanish) on air monitoring and control equipment at the Instituto Tecnológico de Tijuana. Maintain contact with Comisión Federal de Electricidad engineers responsible for operation of wind and geothermal power plants in Mexico, and am comfortable operating in the Mexican business environment.

EXPERT TESTIMONY

- On behalf of Attorney General of Iowa, In re Application of Interstate Power and Light Company for a Generating Facility Siting Certificate, Docket No. GCU-07-01, Iowa Utilities Board, November 9, 2007. Nature of testimony - IGCC with CO_2 control as alternative to pulverized coal-fired boiler.

- On behalf of individuals, the National Parks Conservation Association and Group Against Smog and Pollution, In the Matter of Greene Energy Resource Recovery Project, Plan Approval PA-30-00150A, Pennsylvania Department of Environmental Protection, June 2006. Nature of testimony – best available NO_x control for CFB boiler.

- On behalf of the Consumer Advocate Division of the Public Service Commission of West Virginia, Appalachian Power Company, Application for a Certificate of Public Convenience and Necessity to construct a 600 MW Integrated Gasification Combined Cycle Generating Station in Mason County, Public Service Commission of West Virginia, Case No. 06-0033-E-CN, November 19, 2007. Nature of testimony – challenges of converting IGCC designed without CO_2 capture for later retrofit to CO_2 capture.

- On behalf of Sierra Club, Sierra Club vs. Environment and Public Protection Cabinet and East Kentucky Power Cooperative, Inc., File No. DAQ-27974-037, October 30, 2006. Nature of testimony – best available NO_x control for CFB boiler.

- On behalf of Californians for Renewable Energy, In the Matter of Southern California Edison Company (U 338-E) for Approval of Results of Summer 2007 Track of its New Generation Request for Offers and for Cost Recovery, Application 06-11-007, Public Utilities Commission of California, November 30, 2006. Nature of testimony – cost to ratepayers of peaking gas turbines.

- On behalf of Utility Consumers' Action Network (UCAN), In the Matter of the Application of San Diego Gas & Electric Company (U 902-E) for a Certification of Public Convenience and Necessity for the Sunrise Powerlink Transmission Project, Application 06-08-010, Public Utilities Commission of California, May 2008. Nature of testimony – advantages of distributed generation alternative to new transmission line.

- On behalf of Environmental Health Coalition, In the Matter of: the Application for Certification for the Chula Vista Energy Upgrade Project, Docket No. 07-AFC-4, California Energy Resources Conservation and Development Commission, September 17, 2008. Nature of testimony – cost viability of distributed photovoltaics alternative to peaking gas turbine.

- On behalf of Sierra Club, Sierra Club v. Tennessee Valley Authority, Case No. CV-02-J-2279-NW (N.D. Ala. 2008). Nature of testimony – opacity issues and particulate controls for existing coal-fired boiler.

- In re the PSD Air Quality Permit Application of Hyperion Energy Center South Dakota Department of Environment and Natural Resources, Board of Minerals and Environment, June 25, 2009. Nature of testimony – air emissions from proposed petroleum refinery and best available control technology.

- On behalf of Sierra Club and the National Audubon Society, In The Matter Of Southwestern Electric Power Company (SWEPCO) – Turk Power Plant, Docket No. 08-006-P, Arkansas Pollution Control and Ecology Commission. March 6, 2009. Nature of testimony – best available SO_2 and PM controls for proposed coal-fired boiler.

- On Behalf of Protestant Annie Mae Shelton, In the Matter of Applications of Aspen Power, LLC for TCEQ Air Quality Permit No. 81706, Prevention of Significant Deterioration Air Quality Permit PSD-TX-1089, and HAP 12, SOAH Docket No. 582-09-0636, TCEQ Docket No. 2008-1145-AIR, Before the Texas State Office of Administrative Hearings, March 3, 2009. Nature of testimony – best available NO_x, PM, and CO/VOC controls for biomass boiler.

- On Behalf of Sierra Club and No Coal Coalition, in the Matter of Applications of White Stallion Energy Center, LLC for State Air Quality Permit 86088; Prevention of Significant Deterioration Air Quality Permit Psd-Tx-1160 and for Hazardous Air Pollutant Major Source [FCAA § 112 (G)] Permit Hap-28 and Plant-wide Applicability Limit Pal-48, Texas State Office of Administrative Hearings, November 2, 2009. Nature of testimony – best available NO_x, PM, SO_2, and CO/VOC controls for CFB boilers.

- On behalf of Montana Environmental Information Center and Citizens for Clean Energy, In the Matter of: Southern Montana Electric Generation & Transmission Cooperative – Highwood Generating Station Air Quality Permit No. 3423-00, Montana Board of Environmental Review, Case No. BER 2007-07-AQ, October 2, 2007. Nature of testimony – IGCC with CO_2 control as alternative to coal-fired CFB boiler.

- On behalf of NRDC, Natural Resources Defense Council, Inc., v. Chris Korleski, Erac No. 996266, Erac No. 996267, State of Ohio Environmental Review Appeals Commission, May 11, 2010. Nature of testimony – best available air emission control levels for proposed coal-to-liquids plant.

- On Behalf of Save The Dunes Council, Inc., et al., In The Matter of Objection to the Issuance Of Significant Source Modification Permit No. 089-25484-00453 to BP Products North America Inc. Whiting Business Unit, Cause No. 08-A-J-4115. Nature of testimony – estimation of air emissions from proposed petroleum refinery expansion.

- On behalf of North Carolina Waste Awareness Reduction Network Inc., North Carolina Waste Awareness Reduction Network Inc. v. N.C. Department of Environment and Natural Resources, Division of Air Quality, 08-Ehr-0771, 0835 & 0836, 09-Ehr-3102, 3174 & 3176, North Carolina Office of Administrative Hearings, March 1, 2010. Nature of testimony – best available SO_2 and PM emission controls for proposed pulverized coal-fired boiler.

PUBLICATIONS

Bill Powers, "*Federal Government Betting on Wrong Solar Horse*," Natural Gas & Electricity Journal, Vol. 27, Issue 5, December 2010, pp. 15-22.

Bill Powers, "*Today's California Renewable Energy Strategy—Maximize Complexity and Expense*," Natural Gas & Electricity Journal, Vol. 27, Issue 2, September 2010, pp. 19-26.

Bill Powers, "*Environmental Problem Solving Itself Rapidly Through Lower Gas Costs*," Natural Gas & Electricity Journal, Vol. 26, Number 4, November 2009, pp. 9-14.

Bill Powers, "*PV Pulling Ahead, but Why Pay Transmission Costs?*" Natural Gas & Electricity Journal, Vol. 26, Number 3, October 2009, pp. 19-22.

Bill Powers, "*Unused Turbines, Ample Gas Supply, and PV to Solve RPS Issues*," Natural Gas & Electricity Journal, Vol. 26, Number 2, September 2009, pp. 1-7.

Bill Powers, "*CEC Cancels Gas-Fed Peaker, Suggesting Rooftop Photovoltaic Equally Cost-Effective*," Natural Gas & Electricity Journal, Vol. 26, Number 1, August 2009, pp. 8-13.

Bill Powers, "*San Diego Smart Energy 2020 – The 21st Century Alternative*," San Diego, October 2007.

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